Dean K. Matsuura
Manager
Regulatory Affairs

August 24, 2009

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PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0303 – Advanced Metering Infrastructure Project
Hawaiian Electric Companies' Responses to Information Requests

In accordance with the Stipulated Procedural Schedule in the subject proceeding, enclosed for filing are the Hawaiian Electric Companies[1] responses to information requests ("IRs") submitted by the Consumer Advocate ("CA") and Life of the Land ("LOL"), and the joint IRs submitted by the Hawaii Renewable Energy Alliance ("HREA") and the Hawaii Solar Energy Association ("HSEA").

Enclosed are responses to IRs filed on August 7, 2009: CA IRs 37 through 53, LOL IRs 2 through 41, and HREA-HSEA IRs 14 through 29.[2]

Very truly yours,

for Dean K. Matsuura
Manager, Regulatory Affairs

Enclosures

cc: Division of Consumer Advocacy
Henry Q Curtis (Life of the Land)
Warren S. Bollmeier II (HREA)
Mark Duda (HSEA)

[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.

[2] For reference purposes, the Companies have renumbered LOL-IR-1 through LOL-IR-40 as LOL-IR-2 through LOL-IR-41, and HREA-HSEA-IR-1 through HREA-HSEA-IR-16 as HREA-HSEA-IR-14 through HREA-HSEA-IR-29 to follow in sequential order from previously submitted IRs.

Division of Consumer Advocacy

CA-IR-37

Ref: HECO T-1 and Response to PUC-IR-1 – Total Project Costs.

The Company indicates that the total project costs will total $115,016,000 (see, e.g., HECO T-1, page 7, line 17).

a. Based on information made available, it appears that the total project costs should actually be higher. For instance, in the response to PUC-IR-1, the costs presented in 2016 appear to reflect a significant amount of costs related to the MDMS. If the costs to be incurred in 2016 are included, the total costs from 2010 through 2016 would be $140,282,000. Please explain what these costs in 2016 are.

b. If not explained in the response to part (a) of this information request, please explain why these costs should not be included in the total project costs that have been identified for Commission approval.

Hawaiian Electric Companies' Response:

a. The project cost of $115,016,000 is the total project cost for the 2010-2015 AMI project deployment period. The Hawaiian Electric Companies' response to CA-IR-35, Attachment 1, Table 3 contained a typographical error which resulted in the MDMS costs represented in 2016 to be considerably higher than they should be. The error also resulted in the MDMS costs to be incorrectly represented beyond 2016 as zero in Attachment 1 of the Hawaiian Electric Companies' response to PUC-IR-1. Attachment 1 to this response provides the corrected Attachment 1 to the Hawaiian Electric Companies' response to PUC-IR-1. The costs presented beyond 2015 are recurring O&M and Capital costs reflective of normal business operations with a fully deployed AMI system.

b. See the response to a. above.

Exhibit 19, Table 3 - All AMI Project Costs (in $000s)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
HECO	Proj Mgmt	$843	$869	$896	$915	$935	$954	$975	$996	$1,017	$1,039	$1,062	$1,086
	Meters	$0	$15,901	$16,259	$17,060	$703	$765	$791	$810	$820	$832	$843	$856
	MDMS	$5,668	$4,647	$1,615	$533	$388	$746	$685	$423	$432	$441	$857	$788
	Network	$252	$352	$621	$932	$914	$948	$970	$1,006	$1,044	$1,083	$1,124	$1,169
	Total	$6,763	$21,769	$19,391	$19,440	$2,940	$3,413	$3,421	$3,235	$3,313	$3,395	$3,886	$3,899
MECO	Proj Mgmt	$289	$298	$342	$597	$817	$544	$555	$566	$572	$584	$596	$608
	Meters	$0	$0	$0	$0	$12,425	$276	$327	$336	$344	$351	$359	$366
	MDMS	$1,255	$1,029	$358	$118	$86	$165	$152	$94	$96	$98	$190	$175
	Network	$12	$3	$3	$3	$271	$213	$220	$230	$241	$254	$264	$276
	Total	$1,556	$1,330	$703	$718	$13,599	$1,198	$1,254	$1,226	$1,253	$1,287	$1,409	$1,425
HELCO	Proj Mgmt	$289	$285	$317	$275	$541	$555	$570	$585	$595	$611	$627	$644
	Meters	$0	$0	$0	$0	$0	$15,965	$402	$467	$480	$492	$503	$515
	MDMS	$1,481	$1,214	$422	$139	$101	$195	$179	$110	$113	$115	$224	$206
	Network	$14	$4	$4	$4	$4	$387	$296	$311	$327	$343	$363	$379
	Total	$1,784	$1,503	$743	$418	$646	$17,102	$1,447	$1,473	$1,515	$1,561	$1,717	$1,744
TOTAL	Proj Mgmt	$1,421	$1,452	$1,555	$1,787	$2,293	$2,053	$2,100	$2,147	$2,184	$2,234	$2,285	$2,338
	Meters	$0	$15,901	$16,259	$17,060	$13,128	$17,006	$1,520	$1,613	$1,644	$1,675	$1,705	$1,737
	MDMS	$8,404	$6,890	$2,395	$790	$575	$1,106	$1,016	$627	$641	$654	$1,271	$1,169
	Network	$278	$359	$628	$939	$1,189	$1,548	$1,486	$1,547	$1,612	$1,680	$1,751	$1,824
	Total	$10,103	$24,602	$20,837	$20,576	$17,185	$21,713	$6,122	$5,934	$6,081	$6,243	$7,012	$7,068

		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
HECO	Proj Mgmt	$1,110	$1,135	$1,161	$1,188	$1,215	$1,243	$1,272	$1,302	$1,333	$1,365	$1,398	$1,432	$1,466	$1,502	$29,709
	Meters	$867	$880	$892	$923	$956	$991	$1,027	$1,063	$1,102	$1,142	$1,185	$1,228	$1,272	$1,319	$70,487
	MDMS	$484	$496	$507	$990	$912	$561	$575	$590	$1,152	$1,062	$656	$674	$693	$1,346	$27,194
	Network	$1,212	$1,258	$1,305	$1,354	$1,408	$1,460	$1,516	$1,572	$1,632	$1,696	$1,760	$1,827	$1,895	$2,970	$33,280
	Total	$3,673	$3,769	$3,865	$4,455	$4,491	$4,255	$4,390	$4,527	$5,219	$5,265	$4,999	$5,161	$5,326	$7,137	$160,670
MECO	Proj Mgmt	$621	$635	$648	$662	$677	$692	$707	$723	$740	$757	$774	$792	$810	$829	$16,435
	Meters	$375	$382	$392	$407	$423	$442	$459	$479	$499	$519	$541	$565	$588	$613	$21,468
	MDMS	$107	$110	$112	$219	$202	$124	$127	$131	$255	$236	$145	$149	$154	$299	$6,022
	Network	$289	$302	$318	$331	$346	$363	$380	$399	$416	$435	$455	$477	$501	$544	$7,546
	Total	$1,392	$1,429	$1,470	$1,619	$1,648	$1,621	$1,673	$1,732	$1,910	$1,947	$1,915	$1,983	$2,053	$2,285	$51,471
HELCO	Proj Mgmt	$662	$680	$699	$719	$740	$761	$783	$806	$830	$854	$880	$906	$934	$962	$17,110
	Meters	$530	$543	$556	$582	$607	$636	$665	$695	$726	$758	$794	$831	$869	$909	$28,525
	MDMS	$126	$129	$132	$259	$238	$146	$150	$154	$301	$277	$171	$176	$181	$351	$7,104
	Network	$398	$418	$440	$464	$485	$510	$536	$563	$593	$621	$653	$686	$720	$759	$10,282
	Total	$1,716	$1,770	$1,827	$2,024	$2,070	$2,053	$2,134	$2,218	$2,450	$2,510	$2,498	$2,599	$2,704	$2,981	$63,021
TOTAL	Proj Mgmt	$2,393	$2,450	$2,508	$2,569	$2,632	$2,696	$2,762	$2,831	$2,903	$2,976	$3,052	$3,130	$3,210	$3,293	$63,254
	Meters	$1,772	$1,805	$1,840	$1,912	$1,986	$2,069	$2,151	$2,237	$2,327	$2,419	$2,520	$2,624	$2,729	$2,841	$120,480
	MDMS	$717	$735	$751	$1,468	$1,352	$831	$852	$875	$1,708	$1,575	$972	$999	$1,028	$1,996	$40,320
	Network	$1,899	$1,978	$2,063	$2,149	$2,239	$2,333	$2,432	$2,534	$2,641	$2,752	$2,868	$2,990	$3,116	$4,273	$51,108
	Total	$6,781	$6,968	$7,162	$8,098	$8,209	$7,929	$8,197	$8,477	$9,579	$9,722	$9,412	$9,743	$10,083	$12,403	$275,162

CA-IR-37
DOCKET NO. 2008-0303
ATTACHMENT 1
PAGE 1 OF 1

PUC-IR-1
DOCKET NO. 2008-0303
ATTACHMENT 1
PAGE 1 OF 1
(CORRECTED 8/24/09)

CA-IR-38

Ref: HECO T-1, page 8.

a. Based on the understanding that AMI is intended to be a foundational element of a smart grid future, please discuss how the design and deployment of an AMI system can be reasonably accomplished without having a clear path and/or comprehensive design for the smart grid.

b. Please discuss and/or confirm the possibility that if an AMI system, including the MDMS, is selected before the design for the smart grid is determined, that the design of the smart grid may be limited by the AMI choice made now.

Hawaiian Electric Companies' Response:

a. The Hawaiian Electric Companies held a series of internal discussions to define some preliminary Smart Grid components for each of the Hawaiian Electric Companies' service territories. The Companies' current plan is to refine and incorporate these initial concepts into a detailed Smart Grid plan. Implementation of a Smart Grid will take place over many years; therefore, it is not necessary or possible to develop comprehensive designs for every aspect of a Smart Grid at this time. The design and deployment of an AMI system must take into account the existing and projected technology landscape and strive to incorporate technology elements and plans that will meet today's needs as well as future needs, to a reasonable extent.

b. In addition to its plan to develop a Smart Grid Roadmap, the Companies plan to examine AMI technology, including communications architecture, in the broader context of Smart Grid applications. The Hawaiian Electric Companies are focused on ensuring that the AMI network that is implemented will have the ability to support Smart Grid functionality.

CA-IR-39

Ref: HECO T-2 – Meter Development.

a. Do the Companies contend that each customer and, on a more aggregated basis, customers on a circuit will be able to achieve the same level of benefits as all other individual customers and on a separate circuit basis? If so, please provide the basis for this contention.

b. If the Companies generally agree that it is likely that different customers and areas can provide varying levels of return on investment, please discuss whether the cost effectiveness and practicality of identifying customers and/or areas of high "return" is desirable and feasible.

Hawaiian Electric Companies' Response:

a. The Hawaiian Electric Companies do not contend that each customer or customers on a given circuit will be able to achieve the same level of benefits as all other individual customers and on a separate circuit basis.

b. Different customers in different areas may provide varying levels of return on investment. However, the cost effectiveness and practicality of focusing on customers and/or areas of high "return" is not a feasible scenario given the centralized nature of the proposed Meter Data Management System for all three companies and the significant upfront costs associated with software implementation, integration with the AMI head-end system and the Hawaiian Electric Companies' Customer Information System.

CA-IR-40

Ref: Project Roll-Out.

a. Assuming that the project is approved as proposed by the Companies and reporting requirements are ordered by the Commission to evaluate the success of the proposed project and associated programs, please discuss the possible pros and cons associated with any potential circumstances requiring the Commission to halt the project in order to re-evaluate the project to better achieve project objectives, improve cost effectiveness, and realignment with overall goals (e.g., Energy Agreement, Smart Grid development when the plan is developed, etc.).

b. If not already discussed in part (a) of this information request, please discuss the Companies' thoughts on whether it is possible and/or reasonable to have a deployment plan that will include phases to allow for stakeholders to evaluate the alignment or agreement between the proposed AMI project and other system objectives at certain stages, rather than proceeding without any re-evaluation of whether the proposed project will support other key objectives, such as the smart grid and renewable development.

c. With the continued assumption that reporting requirements are established, if the deployment of the meters and other attendant infrastructure is predicated upon prioritizing areas of highest expected cost effectiveness, please confirm that the reported results are likely to be more favorable than deploying meters in a haphazard plan of first-come, first served. Please provide analyses or other support considered by the Company.

Hawaiian Electric Companies' Response:

a. Assuming that the project is approved as proposed by the Hawaiian Electric Companies and reporting requirements are ordered by the Commission to evaluate the success of the proposed project and associated programs, it would be important for deployment to proceed as expeditiously as possible in order to manage costs and to return expected operational benefits as quickly as possible once the deployment commences. However, incremental project costs could be reasonably controlled if the project delays occurred prior to commencing the project implementation. Project delays after the project commences would result in significant cost additions, including mobilization/demobilization costs associated with the difficulty in retaining the necessary workforce for deployment. The first significant investment in the AMI Project will be in

the Meter Data Management System ("MDMS") and in interfacing the MDMS to both the AMI head-end system and the Companies' Customer Information System. The MDMS will be centralized and will support Hawaiian Electric, HELCO, and MECO. Delays in deploying meters would delay the recognition of the project's quantifiable benefits, thus delaying the return on investment for the MDMS. Incremental project costs, due to delays, prior to the project commencing could be reasonably controlled and may provide additional benefits such as:

1) Providing the Hawaiian Electric Companies time to advance in Smart Grid Roadmap activities (described in the response to HSEA-HREA-IR-22).
2) Provide time for the AMI technologies to advance in their maturity. HECO T-2 (pages 15 and 19) presents information pertaining to the rapidly evolving and maturing AMI technology.
3) Provide time for the capabilities for the Hawaiian Electric Companies' Customer Information System to be able to fully support the AMI capabilities.

b. The Companies do not believe it is reasonable to have a deployment plan that will include phases to allow for stakeholders to evaluate the alignment or agreement between the proposed AMI project and other system objectives at certain stages, rather than proceeding without any re-evaluation of whether the proposed project will support other key objectives, such as the smart grid and renewable development, since this would cause projects delays. Project delays during the project implementation would result in increased costs and increased delays in realizing the quantifiable benefits as described in part a. above. In the alternative, the Companies would recommend that such a revised

deployment plan be developed in order to obtain such an alignment or agreement in advance of full scale deployment. This is based in large part on the significant investment necessary to implement the MDMS and software interfaces prior to full-scale meter deployment.

c. The Companies described the proposed deployment concept in their response to CA-IR-1 (page 2) and in HECO T-2 (pages 11-12). The proposed deployment is focused on geographic areas and meter reading routes to achieve maximum installation efficiency and timely elimination of entire meter reading routes. The Companies have not proposed a haphazard first-come, first served plan. The Companies' responses to CA-IR-10 (page 1) and HSEA-HREA-IR-1 (page 1) discuss the Companies' approach and basis for accommodating "first-come, first-served" requests for advanced meters.

CA-IR-41

Ref: HECO T-2.

A concern was raised regarding the possibility that the regulators cannot evaluate whether the proposed AMI system is an optimal solution for Hawaii and its customers.

a. On page 18 of HECO T-2, the question regarding the regulators' ability to evaluate the project is posed. The response to this issue appears to acknowledge that AMI technologies and products are rapidly evolving and are competitive. The response, however, does not appear to address the regulators' ability to evaluate whether the optimal system has been selected in the absence of a comprehensive business case, including comparative analyses of various alternatives. Please discuss.

b. Please discuss whether it is the Companies' understanding that all MDMS systems are technology neutral. In other words, please confirm that the selection of the proposed Sensus technologies does not limit the possible MDMS solutions and scenarios that the Companies may consider. Please provide support for the Companies' response.

c. If the Companies cannot confirm that MDMS solutions are technology neutral, please discuss the practicality of the following relationships:
   1. selecting the meter technology and vendor without considering the interoperability and compatibility of the meters and MDMS; and
   2. selecting the meter and communications technology without taking into consideration of the smart grid design and the MDMS that will best support that design.

Hawaiian Electric Companies' Response:

a. At the time that the Hawaiian Electric Companies selected the Sensus AMI technology, proven AMI solutions were limited and it would have been difficult to develop a business case that included comparative analyses of various alternatives. The Companies developed a detailed AMI financial model, which clearly identifies the costs and quantifiable benefits of the proposed AMI project and presents an estimated benefit/cost ratio using those estimates. The Hawaiian Electric Companies also provided considerable information pertaining to the merits of the AMI project in part a of their response to CA-IR-7.

b. In general, Meter Data Management Systems ("MDMS") should be considered technology neutral. Selection of the Sensus technology, in and of itself, does not limit the possible MDMS solutions and scenarios that the Companies may consider. All of the MDMS vendors have experience interfacing and operating their MDMS product with the Sensus (Regional Network Interface ("RNI") or other AMI vendor head-end systems. The MDMS vendors' experience will be factored into the MDMS selection since, as with all products, each MDMS has unique strengths and weaknesses. The interfacing costs for each specific MDMS will vary, depending on the MDMS vendor's experience and risk tolerance. For example, eMeter has implementation and operational experience interfacing their MDMS to Alliant Energy's Sensus AMI system and Itron has implementation and operational experience interfacing their MDMS to Southern Company's Sensus RNI. Potential interfacing cost variations are expected to be within the estimated MDMS costs presented in the instant application. The Companies do not anticipate cost overruns.

c. See response to part b.

CA-IR-42

Ref: HECO T-2.

On page 17 of HECO T-2, the Companies appear to acknowledge that the observations that a second technology (in addition to the proposed technology) may provide a practical solution or alternative to the Sensus fixed tower network technology for Molokai and Lanai. The Companies do not, however, indicate what measures they might take for these areas (i.e., Molokai and Lanai), and perhaps, other small, remote areas to make AMI technology and attendant programs available and accessible. Please discuss.

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies plan to investigate the level of radio frequency ("RF") coverage on Molokai and Lanai from the Tower Gateway Basestations ("TGBs") on Maui and Oahu. This investigation can not be finalized until the TGBs on Maui and Oahu are installed and fully operational. Exhibit D of the Sensus Agreement ("Air Model") page 14 indicates that the Maui TGBs will provide partial RF coverage for Molokai and Lanai. However, to achieve full RF coverage, other technology would be required to supplement AMI for Molokai and Lanai. In recent months, Sensus has indicated that they are building a compact TGB ("Mini TGB") that is designed to be installed at utility substations or other remote locations. The Sensus product line also includes FlexNet Network Portals ("FNPs") and FlexNet Remote Portals ("FRPs") which were discussed in Exhibit 11 of the instant Application. Mini TGBs, FRPs and FNPs may be used to economically extend coverage to Lanai, Molokai, and remote areas on the islands of Oahu, Maui, and the Big Island.

CA-IR-43

Ref: HECO T-2.

On page 19, the Companies attempt to address the Consumer Advocate's observation (beginning on page 26 of CA-T-1) that the AMI pilots have been conducted only on Oahu.

a. While the Sensus Agreement has provisions related to failure rates that would allow the Companies to be released from the contractual requirement to purchase 90% of the AMI meters from Sensus, please discuss whether the Companies would still seek cost recovery from ratepayers of the meters and infrastructure already in place that contributed to the findings that performance expectations were not adequate.

b. Please discuss whether ratepayers would be able to receive any type of refund or other benefit for costs recovered from the ratepayers associated with the AMI project due to a "failure" of the AMI meters or any other part of the proposed project. Please provide a detailed discussion of those possible recoveries.

c. In the direct testimony, the Consumer Advocate also made the observation that the pilot program most recently completed by the Companies only evaluated Sensus AMI technology. Please discuss whether the Companies considered the likelihood or possibility that if the pilots also conducted tests of other technologies that different results and findings might have been reached. If the Companies did consider this, please discuss why the Companies chose not to evaluate other technologies concurrently with the Sensus technologies.

    1. If it is the Companies contention that any such pilot would have still resulted in the Sensus technologies and solution to be selected, please provide copies of the documentation relied upon to support the Company's response.

d. HECO asserts that 93 – 95% network coverage will exist with the AMI meters. Please confirm that if 93% is not achieved, it is at the vendors' expense to install additional infrastructure to ensure compliance with this benchmark.

    1. Please discuss what recourse exists if, even after additional infrastructure is installed, 93% is not attained.

    2. If not included in the response to part (1) of this information request, please describe the impact, whether benefit or cost, that customers will experience as a result of any recourse pursued by the Companies with respect to the hypothetical failure of the proposed system to reach at least 93% network coverage.

Hawaiian Electric Companies' Response:

a. Section 2 of the Sensus Agreement (Purchase of Equipment, Warranties, Title, and Risk of Loss) defines specific remedies available to the Hawaiian Electric Companies for a variety of reasons such as Sensus Meter Failure Rate (paragraph 2i), Product Recall (paragraph e), and Equipment Warranty (paragraph d). Pursuant to these provisions, the

Companies would generally recover a portion of the costs from Sensus that resulted from product failures. Section 6 of the Sensus Agreement (Response and Resolution Times: Service Level Agreements) defines specific remedies available to the Companies for the failure of the AMI network to meet performance goals.

b. See the response to part a. for a discussion of remedies associated with the Sensus Agreement. All of the remedies as discussed in part a above are designed to safeguard the Hawaiian Electric Companies and their ratepayers. The remedies would offset either increased costs or reduced quantifiable benefits. The cost recovery would be reflected within the actual project cost and therefore would be reflected in the surcharge adjustment as described in section XI.2 of the instant Application. Remedies associated with the Meter Data Management System ("MDMS") and the integration work for the AMI head-end system and the CIS would be part of the contracts negotiated with the MDMS vendor and the System Integrator.

c. The Companies did not have sufficient resources to perform multiple pilots concurrently. As such, the Companies selected one vendor to perform this evaluation. The information pertaining to the technology selection is presented within Exhibit 3 of the instant Application. With the developments that have taken place in the AMI marketplace in the past several years and in light of major technology selections made by other utilities, it is possible that a different conclusion might be reached but the Companies do not have adequate information to come to that conclusion.

1. See response to part c.

d. Additional infrastructure could be necessary to achieve 93% coverage of the Companies' service area. This could take the form of an additional Tower Gateway Basestation

("TGB") antennae, TGB sites, FlexNet Network Portal ("FNP"), or FlexNet Remote Portals ("FRP"). In accordance with section 3(b) of the Sensus Agreement, Sensus is responsible for all installation, operation and maintenance costs for TGBs. In accordance with section 2(b) of the Sensus Agreement, the Companies are responsible for the installation and maintenance costs for FNPs and FRPs. However, section 2(b)(ii) of the Sensus Agreement places a cap on the Hawaiian Electric Companies' liability by requiring Sensus to reimburse the Hawaiian Electric Companies' costs if the Hawaiian Electric Companies are required to install more FNPs and FRPs than a certain limited quantity defined in the agreement, within the coverage area. The maximum quantity of FNPs and FRPs, within the coverage area, for which the Hawaiian Electric Companies could be held responsible for installation and maintenance costs are 10, 6, and 4 for Hawaiian Electric, HELCO and MECO respectively.

1. See the response to part a.

2. See response to part 1 for the potential impacts to costs. If the AMI system cannot achieve at least 93% network coverage, the benefits for the Meter Reader Savings, Field Service Savings, and Theft Detection will likely be reduced to a proportionate level.

CA-IR-44

Ref: HECO T-2.

The Consumer Advocate discusses the concerns regarding the reasonableness of the project costs and how the Companies' decision to forego a bidding process raises questions. (CA-T-1, pages 28 – 29)

a. While the Companies assert that "substantial technical details" have been provided and that the projected benefits "offset a significant portion" of the project costs, what can regulators do to evaluate whether other less costly alternatives might exist and still achieve the projected levels of benefits.

b. Please discuss whether the Companies can confirm that the proposed project is the least cost (not lowest) reasonable solution.

   1. If the Companies contend that they can confirm this assertion, please provide the basis for the Companies' position and include copies of all documentation relied upon to support this assertion.

   2. If the Companies cannot confirm that the proposed project is the least cost, reasonable solution, please discuss and provide any additional information not already in the record that the regulators can rely upon to come to the conclusion that other possible AMI alternatives should be ignored.

Hawaiian Electric Companies' Response:

a. The Hawaiian Electric Companies made a decision to focus on Sensus AMI technology at a time when choices were limited in the AMI marketplace. On that basis, the Companies developed a detailed AMI financial model to present the costs, benefits, and benefit-cost ratios in order to present the economics of the proposed AMI system. Evaluating other alternatives could only be done through a formal Request for Proposal process, in which the present state of the marketplace is assessed and new cost-benefit analyses are completed.

b. The Companies have presented the available costs and benefits computations based on using the Sensus AMI technology. While the Companies believe that the cost accurately reflects the cost of implementing this technology in the manner described in the

Application, the Companies do not have data on alternatives that can be used to confirm that the proposed project is the least cost (not lowest) reasonable solution.

1. See response to part b.

2. See responses to parts a. and b.

CA-IR-45

Ref: HECO T-2 – Sensus-Owned RNI Integration.

The Company acknowledges that the integration of the Sensus-owned RNI is not an item included in the Sensus Agreement, but that an estimated cost for integration has been included in the Companies' analysis.

a. Please provide the applicable cell and tab references to the Companies' detailed model that identifies the estimated amount for these integration costs that were considered in the analysis but not sought for recovery in the instant docket.

b. If the Companies have yet to determine the provider, scope of services, etc. regarding the integration of the RNI, please provide a discussion of how these estimated costs were derived. Please provide a copy of the support relied upon to determine the Companies' model.

Hawaiian Electric Companies' Response:

a. As stated on page 23 of HECO T-2, *"The Companies plan to address integration in a separate contract with the AMI vendor or more likely, through the scope of work for the systems integrator."* As such, various portions of section V of the AMI model, provided as Attachment 1 to the Hawaiian Electric Companies' response to PUC-IR-23 ("AMI Model"), include the Hawaiian Electric Companies' detailed estimated integration costs for the Systems Integrator and other vendors. Section V of the AMI Model narrative, provided as Attachment 2 to the Hawaiian Electric Companies' response to CA-IR-2 ("AMI Model Narrative"), explains the calculations within the AMI Model. The following sections specifically apply to the integration cost estimations:

V.C.3 – Detailed Requirements Specification section of the Detailed Requirements and Design Phase

V.C.5 – System Design Specification section of the Detailed Requirements and Design Phase

V.C.7 – Travel Expense section of the Detailed Requirements and Design Phase

V.D.1 – MDMS Development Cost and Schedule by Phases section of the MDMS Labor & Integration Assumptions

V.D.2 – Project Management Support section of the MDMS Labor & Integration Assumptions

V.D.4 – Product & System Customization section of the MDMS Labor & Integration Assumptions

V.D.5 – System Integration section of the MDMS Labor & Integration Assumptions

V.D.7 – Software Installation and Management section of the MDMS Labor & Integration Assumptions

V.D.8 – Testing section of the MDMS Labor & Integration Assumptions

V.D.9 – Training, Process & Change Management section of the MDMS Labor & Integration Assumptions

V.D.10 – Production, Transition Rollout Support section of the MDMS Labor & Integration Assumptions

V.D.11 – Travel & Expenses section of the MDMS Labor & Integration Assumptions

b. As stated on page 7 of HECO T-3, the Hawaiian Electric Companies utilized a number of resources to maximize the accuracy of their assumptions. Enspiria Solutions, an experienced systems integrator and AMI consultant was hired to review and refine the cost estimates. The Companies' financial model includes all assumptions and calculations related to estimates of the systems integration costs, including the RNI. Attachment 1 to this response contains the Enspiria Solutions workpapers. The cost assumptions, as documented in Attachment 1 to this response, are used within the AMI Model.

MDMS Cost Schedule

Bidder: N/A

Date: Jun-08

AMI Model Reference		Optional (Y/N)	Total Price
	1. MDMS Software		
	a. Software Licenses (please itemize)		
V.B.2	Core Meter Data Management System	N	
V.B.2	Mass Market Residential	N	$ 325,000
V.B.2	C&I	N	$ 100,000
V.B.2	Customer Care	N	$ 225,000
V.B.2	Revenue Protection	N	$ 160,000
	System Interface APIs	N	Included above
	<list API's if licenced seperately as needed>	N	
	Web Applications	N	Included above
	Interface Adapters	N	*Included above*
	Sensus RNI	N	
	MV-RS	N	
	Turtle	N	
	MV-90	N	
V.B.2	b. Annual Software Maintenance and Support (per year)		
	Required software (add rows to itemize)	N	$ 162,000
	Optional software (add rows to itemize)	Y	NA
	c. Third-party software required (add rows to itemize and explain)		
	- License fee	Y	
	- Annual maintenance and support (per year)	Y	

Services Pricing Schedule

Bidder: N/A Date: Jun-08

AMI Model Reference		Is Item Optional ? (Y/N)	Nature of Price Proposal: Indicate F (firm), E (estimate), or NE (not to exceed)	Price (US$) Based on RACI Matrix	Price (US$) Based On Alternative RACI Proposed (Optional)
	Phase 1				
V.D.2	Project management	N	E	$ 30,000	
V.C.3	Detailed Requirement Specifications	N	E	$ 40,000	All Phases added together
V.C.5	System Design Specifications	N	E	$ 60,000	All Phases added together
V.D.5	System Development		E		
	System Configuration	N	E	$ 20,000	
	AMI Headends Interfaces	N	E	$ 175,000	
	CIS interfaces	N	E	$ 50,000	
V.D.7	Hardware & Software Installation & Management	N	E	$ 10,000	
	Business Process Design	N	E		
	Change Management	N	E		
V.D.8	Testing	N	E	$ 40,000	
V.D.9	Training	N	E	$ 15,000	
V.D.10	Production, Transition & Rollout	N	E	$ 35,000	
	Post-production maintenance & support	N	E		
			E		
V.D.4	Revenue Protection setup and config	N	E	$ 70,000	
V.C.8	Travel Expenses	N	E	$ 15,000	All Phases added together
V.D.11	Travel & Expenses	Y	E	$ 53,400	
			E		
	Phase 1 Total			**$ 613,400**	$ -
	Phase 2				
V.D.2	Project management	N	F	$ 15,000	
V.C.3	Detailed Requirement Specifications	N	F	$ 10,000	All Phases added together
V.C.5	System Design Specifications	N	F	$ 15,000	All Phases added together

Services Pricing Schedule

Bidder: N/A	Date:	Jun-08

V.D.5	System Development					
	System Configuration Enhancements	N	E	$	10,000	
	AMI Headends interface enhancements	N	E	$	20,000	
	CIS interface enhancements	N	E	$	10,000	
	OMS interface	N	E	$	25,000	
	WMS and other interfaces	N	E	$	50,000	
V.D.7	Hardware & Software Installation & Management	N	E	$	10,000	
	Business Process Design	N	E			
	Change Management	N	E			
V.D.8	Testing	N	E	$	30,000	
V.D.9	Training	N	E	$	15,000	
V.D.10	Production, Transition & Rollout	N	E	$	35,000	
V.D.11	Travel & Expenses	Y	E	$	13,200	
			E			
	Other software and tools proposed (explain and itemize)	Y	E			
V.D.4	Load research / DR support	N	E	$	40,000	
V.C.8	Travel Expenses	N	E	$	5,000	All Phases added together
	Phase 2 Total			**$**	**303,200**	**$ -**
	Phase 3					
V.D.2	Project management	N	F	$	15,000	
V.C.3	Detailed Requirement Specifications	N	F	$	10,000	All Phases added together
V.C.5	System Design Specifications	N	F	$	15,000	All Phases added together
V.D.5	System Development					
	System Configuration Enhancements	N	E	$	10,000	
	AMI Headends interface enhancements	N	E	$	20,000	
	CIS interface enhancements	N	E	$	10,000	
V.D.7	Hardware & Software Installation & Management	N	E	$	10,000	
	Business Process Design	N	E			
	Change Management	N	E			
V.D.8	Testing	N	E	$	15,000	
V.D.9	Training	N	E	$	15,000	
V.D.10	Production, Transition & Rollout	N	E	$	15,000	
	Post-production maintenance & support	N	E			
			E			
	Other software and tools proposed (explain and itemize)	Y	E			

Services Pricing Schedule

Bidder: N/A Date: Jun-08

		N	E			
V.C.8	Travel Expenses	N	E	$	5,000	
V.D.11	Travel & Expenses	Y	E	$	13,200	
			E			
	Phase 3 Total			**$**	**153,200**	**$** -
	TOTAL			**$**	**1,069,800**	**$** -

Services Pricing Schedule

Bidder: SI Vendor Date: Jun-08

AMI Model Reference	All Phases	Is Item Optional ? (Y/N)	Nature of Price Proposal: Indicate F (firm), E (estimate), or NE (not to exceed)	Price (US$) Based on RACI Matrix	Price (US$) Based On Alternative RACI Proposed (Optional)
V.D.2	Project management	N	E	$ 566,215	
	Detailed Requirement Specifications	N	E	$ 78,271	Work Completed under R&D
	System Design Specifications	N	E	$ 78,271	Work Completed under R&D
V.D.5	System Development			$ 2,286,912	
	Phase 1				
	Sensus RNI *	N	E	$26,286	
	CIS	N	E	$749,161	
	Installation Management System **	N	E	$210,291	
	Common Integration Infrastructure (Exception Management, Logging, Error, Notification, etc)	N	E	$52,573	
	Phase 2				
	OMS	N	E	$78,859	
	Revenue Protection	N	E	$39,430	
	Residential/C&I Portal (n/a, embedded in MDMS product)	N	E	$0	
	Load Research	N	E	$78,859	
	SynerGEE	N	E	$157,718	
	GIS	N	E	$39,430	
	Proactive Communication Infrastructure	N	E	$78,859	
	LMS	N	E	$157,718	
	Sensus RNI *	N	E	$26,286	
	MV-90 *	N	E	$52,573	
	MV-RS *	N	E	$52,573	
	Turtle *	N	E	$52,573	
	CIS	N	E	$157,718	
	IVR	N	E	$39,430	
	Phase 3				
	Re-system/integration testing ***	N	E	$236,577	
V.D.7	Hardware & Software Installation & Management	N	E	$ 89,841	
V.D.9	Business Process Design	N	E	$ 224,602	
V.D.9	Change Management	N	E	$ 224,602	
V.D.8	Testing	N	E	$ 651,980	
V.D.9	Training	N	E	$ 89,841	
V.D.10	Production, Transition & Rollout	N	E	$ 151,129	
V.D.10	Post-production maintenance & support	N	E	$ 50,376	
	Other software and tools proposed (explain and itemize)	Y	E	-	
V.D.11	Travel Expenses	N	E	$ 539,045	

Services Pricing Schedule

Bidder: SI Vendor	Date:	Jun-08

Other services proposed (explain and itemize)	Y	E	-	
TOTAL			**$ 5,031,085**	**$ -**

Intermediate Calculation Tables:

SI Services Total ($'s) Excluding Expenses	$4,492,040
Allocation per RACI:	
Project management	12.6%
Detailed Requirement Specifications	1.7%
System Design Specifications	1.7%
System Development	50.9%
(add rows to itemize if necessary to identify system modifications, system integration, etc)	
Hardware & Software Installation & Management	2.0%
Business Process Design	5.0%
Change Management	5.0%
Testing	14.5%
Training	2.0%
Production, Transition & Rollout	3.4%
Post-production maintenance & support	1.1%
Total	100.0%

MDMS integration with:	Relative Complexity Analysis (Units of Work)	Middleware implementation multiplier:	Total (Units of Work = ~ 540 hours):
Phase 1			
Sensus RNI *	0.5	1	0.5
CIS	[redacted]9.5	1.5	14.25
CIS <-> Installation Management System **	[redacted]4	1	4
Common Integration Infrastructure (Exception Management, *Logging, Error, Notification, etc*)	1	1	1
Phase 2			0
OMS	1	1.5	1.5
Revenue Protection	0.5	1.5	0.75
Residential/C&I Portal (n/a, embedded in MDMS product)	0	0	0
Load Research	1	1.5	1.5
SynerGEE	2	1.5	3
GIS	0.5	1.5	0.75
Proactive Communication Infrastructure	1	1.5	1.5
LMS	2	1.5	3

Services Pricing Schedule

Bidder: SI Vendor	Date:	Jun-08	
Sensus RNI *	0.5	1	0.5
MV-90 *	1	1	1
MV-RS *	1	1	1
Turtle *	1	1	1
CIS	[redacted]2	1.5	3
IVR	0.5	1.5	0.75
Phase 3			0
Re-system/integration testing ***	4.5	1	4.5
		Grand Total	**43.5**

* - integration development included in MDMS vendor scope, effort reflects SI vendors role in system/integration testing through to go-live support.
** - most likely a point-to-point integration (flat files) between CIS and the Installation Management Vendor. Effort reflects SI Vendors role in system/integration testing through to go-live support.
*** - HELCO/MECO effort only includes the re-system/integration testing of a sub-set of systems (no re-testing CIS, MV90, MV-RS or Sensus integration due to the same instance is used as HECO).

SI Estimates based on past Enspiria projects:

HECO	Note	Multiplyer		
Task 0: Project Management	3x due to POP, but less streneous	2.500000	$501,075	13%
Task 1: Define Solution Specs	1x	1.000000	$138,533	3%
Task 2: Develop Implementation Plan	1x	1.000000	$50,108	1%
Task 3: Construction	10.875x according to Chris's analysis	10.875000	$1,811,055	46%
Task 4: Testing	10.875x according to Chris's analysis	10.875000	$288,487	7%
Task 5: Startup/Roll-out	3x due to 3 roll-outs (HECO/MECO/HELCO)	3.000000	$53,055	1%
Task 6: Construct new Apps	10.875x according to Chris's analysis	10.875000	$769,298	19%
Task 7: Test new Apps	10.875x according to Chris's analysis	10.875000	$288,487	7%
Task 8: Startup/Rollout New Apps	3x due to 3 roll-outs	3.000000	$75,161	2%
			$3,975,256	
	Fixed Price Contingency	13.0%	$516,783	
	Grand Total		**$4,492,040**	

CA-IR-45
DOCKET NO. 2008-0303
ATTACHMENT 1
PAGE 8 OF 19

Services Pricing Schedule

Bidder: CIS Team/Vendor | Date: Jan-08

AMI Model Reference		Is Item Optional ? (Y/N)	Nature of Price Proposal: Indicate F (firm), E (estimate), or NE (not to exceed)	Price (US$) Based on RACI Matrix	Price (US$) Based On Alternative RACI Proposed (Optional)
	All Phases				
V.D.2	Project management	N	E	$ 47,500	
V.C.3	Detailed Requirement Specifications	N	E	$ 75,000	
V.C.5	System Design Specifications	N	E	$ 50,000	
	System Development			$ 190,000	Task to be perfromed by the SI
	Phase 1				
	Support Integrations with MDMS	N	E	$49,565	
	Support Integrations with Installation Management System	N	E	$24,783	
	Internal CIS Modifications	N	E	$33,043	
	Phase 2				
	Support Integrations with MDMS	N	E	$82,609	
	Support Integrations with Installation Management System	N	E	$0	
	Internal CIS Modifications	N	E	$0	
	Phase 3				
	N/A	N	E	$0	
V.D.7	Hardware & Software Installation & Management	N	E	$ 23,750	
	Business Process Design	N	E	$ -	
	Change Management	N	E	$ -	
V.D.8	Testing	N	E	$ 142,500	
V.D.9	Training	N	E	$ 23,750	
V.D.10	Production, Transition & Rollout	N	E	$ 47,500	
	Post-production maintenance & support	N	E	$ 23,750	
	Other software and tools proposed (explain and itemize)	Y	E	-	
V.C.7 & V.D.11	Travel Expenses	N	E	$ 84,000	
	Other services proposed (explain and itemize)	Y	E	-	
	TOTAL			**$ 707,750**	**$ -**

Services Pricing Schedule

Bidder: CIS Team/Vendor	Date:	Jan-08

Intermediate Calculation Tables:

CIS configuration/customization/API development to support AMI/MDMS project:	Relative Complexity Analysis
Phase 1	
Support Integrations with MDMS	3
Support Integrations with Installation Management System	1.5
Internal CIS Modifications	2
Phase 2	
Support Integrations with MDMS	5
Support Integrations with Installation Management System	0
Internal CIS Modifications	0
Phase 3	
N/A	0
Grand Total	**11.5**

CIS Team-Vendor Services References/Assumptions:

Using Other ESI Projects as a reference.

- Other ESI Projects CIS vendor priced AMI integration support at $100k.
- Work substantially performed off-shore.
- Services included
  - Participation in requirements gathering
    Design, development and Unit test of file production in AMI format
  - Bug fixes etc
- Development/interface included
  - *DB* Sync
  - Route Request and Pre-Installation
  - Post-Installation
  - Numerous internal CIS modifications (AMI deployment status if a route/meter, tracking the AMI network id associated with a service point, etc)
- CIS did *not*
  - *own the requirements documentation (participation only)*
  - participate in system testing through to the go-live production process (bug fixes only)

Assumptions:

- Each of the 4 development/interface items above are equivalent in effort
- *Each individual item = 1 Unit of Work (hence, CIS work equals 4 Units of Work).*
- CIS processing/producing files as defined by AMI Standard Interface Specification is equivalent to the effort required of the HECO CIS vendor to support and expose the necessary data via an API as needed for MDMS integration at HECO (for an equivalent number of integrations).
- Additional HELCO/MECO (phase 3) effort is N/A. No additional effort from CIS Vendor for HELCO/MECO deployment.
- HECO's Peace work will be off-shored in Manila as per Other ESI Projects CIS work (and hence priced similarly)

CIS configuration/customization/API development to support AMI/MDMS project:	Units of Work (as per Other ESI Projects comparison)
Phase 1	
Support Integrations with MDMS	3
Support Integrations with Installation Management System	1.5
Internal CIS Modifications	2
Phase 2	
Support Integrations with MDMS	5
Support Integrations with Installation Management System	0

CIS Team-Vendor Services References/Assumptions:

Internal CIS Modifications	0
Phase 3	
N/A	0
Grand Total	**11.5**
Multipler to include the extra services expected of the vendor (as per the HECO RACI) in comparison to Other ESI Projects	**2**
Total	**23**

Summary:

- Baseline, Other ESI Projects CIS effort = 4 Units of Work ($100k)
  - HECO CIS Team/Vendor effort = 23 Units of Work
  - HECO CIS Team/Vendor effort (Phase 0-3) = $575k
  - Subtract $100k already forecast for Phase 0 effort, HECO CIS Team/Vendor effort (Phase 1-3) = **$475k**

Services Pricing Schedule

Bidder: "Other Legacy Systems" Team/Vendor | Date: Jun-08

AMI Model Reference		Is Item Optional ? (Y/N)	Nature of Price Proposal: Indicate F (firm), E (estimate), or NE (not to exceed)	Price (US$) Based on RACI Matrix	Price (US$) Based On Alternative RACI Proposed (Optional)
	All Phases				
V.D.2	*Project management*	N	E	$ 52,500	
V.C.3	Detailed Requirement Specifications	N	E	$ 52,500	
V.C.5	System Design Specifications	N	E	$ 52,500	
V.D.4	System Development			$ 157,500	
	Revenue Protection teams (and/or external vendors, is in Phase 2.				
V.D.7	Hardware & Software Installation & Management	N	E	$ 26,250	
	Business Process Design	N	E	$ -	
	Change Management	N	E	$ -	
V.D.8	Testing	N	E	$ 105,000	
V.D.9	Training	N	E	$ 26,250	
V.D.10	Production, Transition & Rollout	N	E	$ 26,250	
V.D.10	Post-production maintenance & support	N	E	$ 26,250	
	Other software and tools proposed (explain and itemize)	Y	E	-	
V.C.7 & V.D.11	Travel Expenses	N	E	$ -	
	Other services proposed (explain and itemize)	Y	E	-	
	TOTAL			**$ 525,000**	$ -

Other Legacy System Team-Vendor Services References/Assumptions:

Basic Interface Assumption

- $50k for the services work from the vendor per interface to support the requirements through testing and go-live effort (does not include the building of the integrations, as per this is in the SI vendors scope).
- $50k assumes existing API's are reused (little to none API changes are required).

	Complexity (in relation to OMS vendor support/integration)	Comments	Multiplier ($50k per)	Cost / System
Revenue Protection (MS Access)	0.5	Assume no new API's needed. Validated revenue protection issues sent to system as they are today. Services for Requirements->Go-live support.	50000	$25,000.00
IVR (Avaya)	0.5	Minor re-configuration/API-effort to initiate 'one demand read request' as per customer entered options. In addition to services for Requirements->Go-live support.	50000	$25,000.00
Load Research (SAS)	1	Assume minor configuration/API-work to support the "Loading of interval load data and events.. Etc". In addition to services for Requirements->Go-live support.	50000	$50,000.00
SynerGEE	4.5	Assume configuration/API-work required to support a) "Periodic Update if Virtual Meter Peak Loads", b) "Virtual Meter Definitions" and c) "System Load Snapshot" updates. In addition to services for Requirements->Go-live support.	50000	$225,000.00
GIS (Intergraph)	2	Assume some confguration/programmatic changes to *support export of "Virtual Meter Definitions" including* tracing feeders connectivity from virtual meter points to export the downstream meters associated with the virtual meter point. In addition to services for Requirements->Go-live support.	50000	$100,000.00

Other Legacy System Team-Vendor Services References/Assumptions:

LMS (Yukon)	2	Assume '0.5' effort to provide the services for Requirements->Go-live support in relation to exposing *via an API when a "DPP/Load Control" event occurrs.* Assume '1.5' effort for provide API's to import "Interval Data for Customer on Load Control Programs" and use the data in a meaningful way.	50000	$100,000.00
		Total		**$525,000.00**

Services Pricing Schedule

Bidder: AMI Vendor SI Services | Date: Jun-08

AMI Model Reference		Is Item Optional ? (Y/N)	Nature of Price Proposal: Indicate F (firm), E (estimate), or NE (not to exceed)	Price (US$) Based on RACI Matrix	Price (US$) Based On Alternative RACI Proposed (Optional)
	All Phases				
V.D.2	Project management	N	E	$ 15,000	
V.C.3	Detailed Requirement Specifications	N	E	$ 20,000	
V.C.5	System Design Specifications	N	E	$ 20,000	
V.D.4	System Development			$ -	
	(add rows to itemize if necessary to identify system modifications, system integration, etc)				
V.D.7	Hardware & Software Installation & Management	N	E	$ 30,000	
	Business Process Design	N	E	$ -	
	Change Management	N	E	$ -	
V.D.8	Testing	N	E	$ 60,000	
	Phase 1	N	E	$ 30,000	
	Phase 2	N	E	$ 30,000	
	Phase 3	N	E	$ -	
V.D.9	Training	N	E	$ 15,000	
V.D.10	Production, Transition & Rollout	N	E	$ 15,000	
V.D.10	Post-production maintenance & support	N	E	$ 15,000	
	Other software and tools proposed (explain and itemize)	Y	E	$ -	
V.C.7 & V.D.11	*Travel Expenses*	N	E	$ 30,500	
	Other services proposed (explain and itemize)	Y	E	$ -	
	TOTAL			**$ 220,500**	$ -

AMI Vendor SI Services References/Assumptions:

Basic Interface Assumption

- $50k for the services work from the vendor per interface to support the requirements through testing and go-live effort (does not include the building of the integrations, as per this is in the SI vendors scope).
- $50k assumes existing API's are reused (little to none API changes are required).

Assumptions:

- The necessary RNI functionality and API's will be part of the RNI product; no new API development is needed.
- Sensus RNI integration services are $200/hour
- Sensus will support the integration at HECO. No involvement expected during the HELCO/MECO rollout.

	Complexity (in relation to OMS vendor support/integration)	Multiplier ($50k per)	Cost / System
Phase 1			
Account, Service Point, Hard Meter Configuration	1	50000	$50,000.00
Soft Meter Configuration	0.5	50000	$25,000.00
Soft Meter Configuration Command	0.5	50000	$25,000.00
Read Data, Alarms (e.g. Tamper) and Meter Diagnostic	0.5	50000	$25,000.00
Phase 2			
Real-time Read/Status Request/Response	1	50000	$50,000.00
Outage/Restoration Notifications	0.5	50000	$25,000.00
Real-time Remote Connect/Disconnect Request/Response	*1*	*50000*	*$50,000.00*
Phase 3			
N/A	0	50000	$0.00
		Total	**$250,000.00**

Summary:

- AMI vendor effort for SI service (Phase 0-3) = $250k
- Subtract $100k already forecast for Phase 0 effort, AMI Vendor effort for SI suport (Phase 1-3) = **$150k**

Services Pricing Schedule

Bidder: Meter Installation Vendor SI Services

Date: Jun-08

AMI Model Reference		Is Item *Optional* ? (Y/N)	Nature of Price Proposal: Indicate F (firm), E (estimate), or NE (not to exceed)	Price (US$) Based on RACI Matrix	Price (US$) Based On Alternative RACI Proposed (Optional)
	All Phases				
V.D.2	*Project management*	N	E	$ 5,000	
V.C.3	Detailed Requirement Specifications	N	E	$ -	
V.C.5	System Design Specifications	N	E	$ -	
V.D.4	System Development			$ -	
	(add rows to itemize if necessary to identify system modifications, system integration, etc)	N	E		
V.D.7	Hardware & Software Installation & Management	N	E	$ 10,000	
	Business Process Design	N	E	$ -	
	Change Management	N	E	$ -	
V.D.8	Testing	N	E	$ 20,000	
V.D.9	Training	N	E	$ 5,000	
V.D.10	*Production, Transition & Rollout*	N	E	$ 5,000	
V.D.10	Post-production maintenance & support	N	E	$ 5,000	
	Other software and tools proposed (explain and itemize)	Y	E	$ -	
V.D.11	Travel Expenses	N	E	$ 8,500	
	Other services proposed (explain and itemize)	Y	E	$ -	
	TOTAL			***$ 58,500***	$ -

Installation Vendor SI Services References/Assumptions:

Basic Interface Assumption

- $50k for the services work from the vendor per interface to support the requirements through testing and go-live effort (does not include the building of the integrations, as per this is in the SI vendors scope).
  - $50k assumes existing API's are reused (little to none API changes are required).

Assumptions:

- The necessary functionality and API's will be part of the Installation Vendors product; no new API development is needed.
- To support both the Installation Vendor integrations, the effort is 1X the services work for OMS product vendor support/intgration.
- Installation Vendor vendor effort for SI service = 50k

CA-IR-46

Ref: HECO T-3 – Meter Accuracy Benefits.

a. Please confirm that the calculated meter accuracy benefits to be offset against costs will be calculated as a function of meters that have been installed regardless of any other factor, such as the age of the non-AMI meters replaced, sales for any given year and the assumed 0.4% factor.

b. Notwithstanding the Companies' assertions that these benefits are quantifiable, it appears that the Companies are not proposing to use these savings or benefits to offset the costs to be recovered from ratepayers. If it is the Companies' position that these costs are quantifiable and realizable, please explain why the benefit should not be used to determine the net costs to be recovered through a surcharge or base rates.

c. Please provide a copy of the HECO Meter Accuracy Study dated April 30, 2007 that supports the assumed factor of 0.40%

   1. If the study only analyzes 500 meters in HECO's service territory, please discuss whether it is reasonable to assume that the findings should also be applicable to MECO and HELCO. Please provide a copy of any analyses that supports the position.

   2. Please discuss whether the results of the study are comparable to results that might be expected from a study analyzing a broader range of samples (e.g., an industry or national study). Please provide a copy of any supporting documentation.

Hawaiian Electric Companies' Response:

a. The calculated meter accuracy benefits were calculated as a function of meters that would be installed during the AMI project, regardless of other factors, such as the age of the non-AMI meters replaced and sales for any given year. The 0.4% factor is based on testing of a sample of meters that were replaced by Hawaiian Electric.

b. As explained in part c.1 of the Hawaiian Electric Companies' response to CA-IR-36, these benefits result in higher sales and thus higher revenues, which will flow to the Hawaiian Electric Companies' customers through the proposed revenue balancing account in the sales decoupling mechanism, if approved by the Commission (Decoupling Proceeding, Docket No. 2008-0274). If these benefits occur prior to the approval of the

sales decoupling mechanism, these benefits will naturally accrue to ratepayers in the form of reduced revenue requirements attributable to a reduction in systems losses.

c. The Meter Accuracy Study, dated April 30, 2007, is attached as Exhibit 16 to the instant Application.

1. The study analyzes 500 meters in Hawaiian Electric's service territory, although the Companies acknowledge that there may be some variation in accuracy savings among the Companies' meters due to differences in age, manufacturer, and operating environments. Manpower constraints at HELCO and MECO constrained the Companies' ability to conduct a specific test program for MECO and HELCO meters, but this could be addressed in the future if it is deemed reasonable by the commission.

2. A study analyzing a broader range of samples (e.g., an industry or national study) would not generally be useful. Hawaii's unique island environment and specific mix of meter brands would decrease the applicability of such studies.

CA-IR-47

Ref: HECO T-3 – Energy Theft Recovery.

a. Please confirm that the calculated Energy Theft Recovery benefits to be offset against costs will be calculated as a function of meters that have been installed regardless of any other factor, such as the, sales for any given year and the assumed 0.14% factor.

b. Notwithstanding the Companies' assertions that these benefits are quantifiable, it appears that the Companies are not proposing to use these savings or benefits to offset the costs to be recovered from ratepayers. If it is the Companies' position that these costs are quantifiable and realizable, please explain why the benefit should not be used to determine the net costs to be recovered through a surcharge or base rates.

c. Assuming that the Companies are allowed to recover the net costs of the proposed project through a surcharge, please confirm that the additional costs included in and recovered through base rates, set through a rate filing subsequent to the project, would no longer be recovered through the surcharge as well the estimated energy theft recovery savings would be excluded because the assumption would be that the savings have been reflected in test year sales. If this understanding is incorrect, please clearly indicate how the savings will be reflected against the recovery of project costs both in the surcharge and through base rates.

d. It appears that the proposed factor of 0.14% is based on either an AMR book or by testimony by San Diego Gas & Electric. Please provide a copy of the relevant document that supports the assumed factor of 0.14%

   1. If the study relies on meters in another service territory, or other data not relevant to Hawaii, please discuss whether it is reasonable to assume that the findings should also be applicable to HECO, MECO and HELCO. Please provide a copy of any analyses that supports the position.

Hawaiian Electric Companies' Response:

a. The Energy Theft Recovery benefits were estimated as a function of meters that would be installed as part of the AMI project. Forecasted sales were used to calculate the resulting benefit, using a factor of 0.14% based on data from various sources.

b. As explained in part c.1 of the Hawaiian Electric Companies' ("Companies") response to CA-IR-36, These benefits result in higher sales and thus higher revenues, which will flow to the Companies' customers through the proposed revenue balancing account in the sales decoupling mechanism, if approved by the Commission (Decoupling Proceeding,

Docket No. 2008-0274). If these benefits occur prior to the approval of the sales decoupling mechanism, these benefits will naturally accrue to the ratepayer in the form reduced revenue requirements attributable to reductions in system losses.

c. Assuming that the Companies are allowed to recover the net incremental costs of the proposed project through a surcharge, the Companies confirm that the additional costs included in and recovered through base rates, set through a rate filing subsequent to the project, would no longer be recovered through the surcharge. The estimated energy theft recovery savings would be excluded as well because the assumption would be that the savings have been reflected in test year sales.

d. The calculation for the energy theft factor is presented in Exhibit 17 of the instant Application. The following supporting documentation for the calculation of the energy theft factor was submitted in the response to CA-IR-2:

Attachment 9 – EPRI Revenue Loss Assessment (EPRI)

Attachment 10 – AMR for Theft-Chartwell (Chartwell)

Attachment 11 – SDG&E AMI Application Chapter 29 (PUC State of California)

1. As stated on page 14 of HECO T-3, energy theft occurs in Hawaii, as in other locations. The Companies utilized the best available information to formulate the estimated energy theft basis within their territories. The Companies have no information indicating that the level of energy theft in Hawaii differs from the level of theft represented in their estimate.

CA-IR-48

Ref: HECO T-3 – Meter Capital Savings.

The Consumer Advocate has questioned whether the projected meter capital savings are truly savings that should be used to evaluate the project. The Companies assert that it is reasonable to treat these projected amounts as savings.

a. If the Companies contend that these projected savings are realizable, please explain why these costs should not be used as an offset to the costs that will definitely be incurred and recoverable from ratepayers.

b. Please confirm that the AMI meters are expected to be more expensive and have shorter lives than non-AMI meters.

Hawaiian Electric Companies' Response:

a. The projected meter capital savings will be reflected in a reduction of the capital budget requirements of the Meter and Engineering Services Division of the Customer Installations Department.

b. The Hawaiian Electric Companies confirm that the cost of the AMI meters will be more expensive than non-AMI meters. When compared to non-AMI meters, especially electro-mechanical meters, the AMI meters would be expected to have shorter lives.

CA-IR-49

Ref: Expected Cost/Benefit Ratios.

a. The Companies have indicated that it relied upon a 1% replacement value for AMI meters. Please provide the basis for this value as used in the Companies' calculations other than assertions or agreed upon values in the Sensus Agreement. Assuming that the source is the FlexNet RMA Analysis, please provide a copy of that analysis.

b. Please confirm that if the replacement value is higher than 1%, the payback periods are longer and the B/C ratios are lower.

c. The Consumer Advocate indicated that given the magnitude of the project costs, one might expect that the useful life for the underlying systems, such as the MDMS, might be longer than 12 years. The Companies indicate that, given the "rapid pace of technological change[,]" a useful life shorter than 12 years might be more reasonable (HECO T-5, page 14). Please confirm that if a shorter depreciable life is used for the proposed project that this has an adverse impact on the calculated payback periods and B/C ratios since one would have to assume that if certain components have shorter useful lives, replacements, upgrades and other additional costs would be incurred.

   1. If the Companies disagree with this assessment, please explain how the Companies can contend that items with a shorter useful life do not require additional costs in the forms or replacement, repair, upgrades, etc. and how these additional costs do not have an adverse impact on the findings that the proposed project is cost effective.

Hawaiian Electric Companies' Response:

a. The Hawaiian Electric Companies ("Companies") AMI financial model uses a 1% replacement value for AMI meters. Current failure statistics (see Attachment 1 of this response) for the iConA residential meter indicate that field failures which can be duplicated in the meter shop are running at 1% while overall failure rates are 3.1% (including out-of-box failures of 2%). Out-of-box failures and failures in excess of 1% during the deployment period are covered under the Sensus Agreement, including all freight charges. Sensus is building a Quality Assurance organization in order to address all aspects of the design and manufacturing process, which should reduce meter failure rates.

b. The Companies confirm that if the replacement level is higher than 1%, the payback periods would be longer and the benefit-cost ratios would be lower.

c. The AMI financial model assumes an initial cost of ownership and recurring replacements (i.e., meter failures) and upgrades such as software maintenance during and after the deployment. If there were a compelling reason for the Companies to modify or replace a component of the AMI system due to a significant change in technology, this would result in increased costs that would need to be weighed against the incremental benefits. Alternatively, if such a technological change were driven by the inability to operate or support the form of the AMI system in existence at that time, then the added costs would reduce the overall benefit-cost ratio for the AMI system as stated by the Consumer Advocate.

1. The Companies concur with the Consumer Advocate's position in this regard.

Total Meters Purchased	
iConA, form 1S	96
iConA, form 2S	2208
iConA, form 2S (CL320)	128
iConA, form 12S	192
total =	2624

Total Meter Currently Installed (8/13/09)	
	1673

Approximate Meters In Inventory	
iConA, form 1S	84
iConA, form 2S	608
iConA, form 2S (CL320)	112
iConA, form 12S	77
total =	*881*

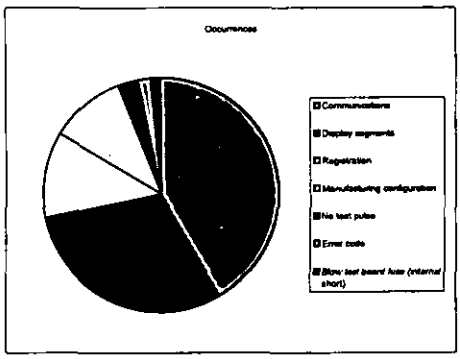
RMA Statistics from October 2008 to present

Summary actual	Count	Rate	
total failures =	67	2.6%	of total meters purchased
total out of box failures =	43	1.6%	of total meters purchased
total unduplicated field failures =	10	0.6%	of current installed meters
total duplicated field failures =	14	0.8%	of current installed meters

Interpolated annual failure rate	Rate	
total failures =	3.1%	of total meters purchased
total out of box failures =	2.0%	of total meters purchased
total unduplicated field failures =	0.7%	of current installed meters
total duplicated field failures =	1.0%	of current installed meters

RMA number	Meters Returned	Date
IC-16371-84901	19	10/07/08
IC-17156-76394	16	11/20/08
IC-18186-39195	18	03/16/09
IC-17184-50473	3	04/02/09
TBD	2	
Not Returned (could not dup)	9	
total =	67	

Count by Symptom	Occurrences	
Communications	28	41.8%
Cannot install with M900 handheld		2
Does not respond to ping		9
Cannot install and does not ack ping		7
Stopped delivering OTA reads		9
Does not send set-up message		1
Display segments	20	29.9%
missing segments		5
display blank		15
Registration	8	11.9%
Manufacturing configuration	7	10.4%
No test pulse	2	3.0%
Error code	1	1.5%
Blow test board fuse (internal short)	1	1.5%
total =	67	



Could Not Duplicate Detail	
No OTA reads	7
Blank	4
No HH install	1
(3 returned on special RMA IC-17184-50473)	

Days Installed Before Failure		
Out of box failures =	43	
Average days in service =	*106*	*of all field failures*
Failures within 30 days =	4	
Failures between 30-60 days =	7	
Failures between 60-90 days =	4	
Failures after 90 days =	9	

CA-IR-50

Ref: Lifeline.

a. The Company is proposing a flat credit for customers who qualify for Lifeline assistance. However, with the expectation that electricity costs will continue to increase due to various factors (e.g., fuel prices, aggressive capital investment by electric companies to meet clean energy initiatives, etc.), is it the Company's assertion that this credit will be sufficient to help customers continue to receive at least basic level electricity needs. Please provide any analyses, etc. that the Companies might have to support this expectation for each service territory.

b. Has the Company conducted any studies to determine whether low income families in Hawaii will, on average, be able to receive benefits on the same level as other residential customers in various higher income brackets. Please do not limit the Companies' response to the meter accuracy, energy theft, field services and meter reading. Please insure that the response considers TOU, DR programs and other benefits that rely on the informational and advanced capabilities that the AMI meters are supposed to deliver in comparison to non-AMI meters.

Hawaiian Electric Companies' Response:

a. The Hawaiian Electric Companies acknowledge that electricity costs could increase over time due to a variety of factors. The Hawaiian Electric Companies understand that if electricity costs increase, an increase in the lifeline rate benefit may be reasonable. Further, the Hawaiian Electric Companies could seek adjustments to eligibility requirements, enrollment procedures, and other program parameters, as described on page 12 of its application for a Lifeline Rate Program in Docket No. 2009-0096:

> "At this time, the Companies believe these residential bill impacts will strike a balance between benefits received by the Lifeline Rate Program participants and the rate adjustments paid by all ratepayers. However, the Companies may need to adjust program parameters once experience in program participation is developed (e.g., at least one year of program implementation experience)."

b. The Hawaiian Electric Companies have not conducted any such studies. The Hawaiian Electric Companies expect the benefits arising from reduced labor expenses, meter accuracy gains, and energy theft recovery (Hawaiian Electric Companies Application,

pages 41-45) to accrue to all customers. Opportunities to participate in time-of-use rates and demand response programs will be available to all residential customers, not just certain income segments of the residential class.

CA-IR-51

Ref: TOU Rates.

a. One common criticism of TOU rates relate to how certain customers will not be able to modify their consumption patterns to take advantage of lower rates during off-peak hours (e.g., families who have to cook, bathe, etc. during the 5 pm through 9 pm hours). While these customers would be able to "benefit" from the anticipated meter accuracy, energy theft, reduction in meter reading and field services, the ability to benefit from some of the rate options (TOU, dynamic response, etc.) will be limited. Is it HECO's opinion that these customers will receive an equal opportunity as others with respect to the possible benefits from a TOU? Please discuss.

b. If not already discussed, please discuss what programs might be available to the customers described above to help create opportunities to receive an equitable share of the possible benefits from an AMI system.

c. If there are no anticipated programs specifically designed to help those customers who will be unable to take advantage of TOU rates and will need to opt-out of TOU rates in order to avoid paying more on their electricity bill, please discuss whether, from that customer's stand point, AMI meters are a good decision.

Hawaiian Electric Companies' Response:

a. Yes, it is the Hawaiian Electric Companies' opinion that each residential customer will have an equal opportunity to utilize the available time-of-use ("TOU") rate options (it should be noted that the proposed TOU rate option for residential customers has an on-peak period from 3pm to 8pm, daily) that accompany the implementation of AMI. Customers choose what electricity-using activities to participate in during on-peak hours. The proposed TOU rate option for residential customers is designed such that customers must modify their consumption patterns in order to achieve lower electric bills under the TOU rate option.

In addition, since the TOU rate is optional, residential customers who choose not to modify their consumption patterns can remain on the regular Schedule R rate schedule.

b. See the response to part a. above.

c. As discussed in part 'a' above, the Hawaiian Electric Companies' TOU rate proposal for residential customers is an optional rate. Residential customers do not have to participate in the TOU rate option. As indicated in HECO T-7, the Hawaiian Electric Companies have not proposed mandatory TOU rates for residential customers after the AMI meter placements are completed because the Companies are concerned about and are still assessing the potential impact to customer bills. Even if residential customers are unable to successfully participate in TOU rates, they, as well as all other customers, will benefit from AMI system's reduced labor costs, meter accuracy gains, and energy theft recovery, as described at pages 40-45 and as estimated in Exhibit 19, Table 12 of the Application in this docket.

CA-IR-52

Ref: TOU Rates.

a. Please identify any other jurisdictions that the Companies are aware where customers are subject to both TOU and decoupling.
b. For each of the identified jurisdictions, please provide copies of any evaluations or studies that may be available on the synergies or opposing effects that may result from customers having to deal with both TOU rates, while also being subject to a decoupling mechanism.

Hawaiian Electric Companies' Response:

a. There are many jurisdictions in which decoupling has coincided with time-of-use ("TOU") and other forms of peak load pricing. Here are some illustrative examples:

California

Decoupling for California's electric utilities extends to all customer classes. TOU pricing was implemented for most large volume customers around the time that decoupling was first introduced in the early 1980s. The decision approving the first decoupling plan for Southern California Edison stated that "the adoption of a revenue adjustment mechanism is effective in eliminating disincentives for the utility to promote the conservation *and rate design policies* enunciated by this Commission.[1]" TOU pricing for residential customers was also available in the 1980s. Inverted block rates were widespread for small volume customers without TOU meters in the 1970s.

The power crisis heightened the interest of state regulators in peak load pricing. TOU pricing became mandatory for all customers with maximum demand greater than 200 kW. More ambitious peak load pricing programs were instituted soon after the reimposition of decoupling. Pursuant to Pursuant to D. 03-03-036, a Statewide Pricing

[1] D. 82-12-055 (1982) p. 17.

Pilot has tested the impact of TOU and critical peak pricing tariffs on residential and commercial customer usage patterns. Many customers with solar photovoltaic ("PV") facilities have participated in TOU pilots. Pursuant to the 2003 Vision Statement in D.03-06-032 and Energy Action Plan II in 2005, a more sweeping program was instituted to go beyond TOU pricing to make dynamic rates available to all customers using AMI, beginning with large volume customers. A remarkable number of peak load pricing options are now available to non-residential customers.

All three major California electric utilities are in the process of implementing systemwide AMI. Pending the completion of this effort, small volume customers face inverted block rates for base rate inputs that discourage peak system loads. For example, a typical residential customer of Pacific Gas & Electric's distribution services faces a low $3.58 minimal monthly bill and 5 tiers of volumetric charges ranging from $ 0.037 for the lowest tier to $ 0.16 for the highest tier. Residential TOU prices also involve inverted block rates.

Consolidated Edison (2008-)

Consolidate Edison's ("Con Ed") decoupling plan extends to most service classes. At the inception of decoupling, the company already offered voluntary time TOU rates to most customer classes and mandatory TOU rates to some classes. Other customers paid inverted block rates. For example, in summer the residential energy delivery charge was 25 cents on peak and 0.81 cents off peak. All other residential customers paid low customer charges and seasonal multitier volumetric rates with a gradual inversion. In the 2007 filing in which decoupling was approved, Con Ed successfully proposed to extend mandatory hourly pricing to customers with maximum demand greater than 500 kW.

The company sells transmission congestion credits and obtains substantial revenue from the New York ISO. A $150 million credit was factored into the approved 2008 revenue requirement. The Company has proposed system-wide deployment of AMI but has thus far gained approval only for demonstration projects.

Idaho Power Company (2007-2009)

The Idaho Power Company decoupling plan pertains only to residential and small general service customers. It is the outcome of a generic hearing that addressed financial disincentives to investment in energy "efficiency". There was little discussion in the filing of the impact of decoupling on TOU pricing. However, the Commission in its order approving the plan acknowledged the benefits of decoupling in promoting energy efficiency *and "DSM"*. The Commission also implied in the order that decoupling makes the company indifferent to reduced energy consumption *and demand.*

The company had TOU and critical peak pricing pilots underway for residential customers participating in an AMI pilot before the start of decoupling. No expansion of the pilot program has occurred under decoupling. However, the company has proposed a system-wide deployment of AMI beginning in 2009, touting among other things its ability to facilitate dynamic pricing.

Portland General Electric (2009-2011)

The decoupling plan doesn't extend to the company's largest customers. At the inception of decoupling, TOU pricing was an option for small business customers but not residential customers. However, residential customers face inverted block rates. The company commented in its rate design testimony that "absent our decoupling proposal,

we would advocate for higher customer charges to reduce the impact of recovering fixed distribution costs on a volumetric basis".

No major rate design initiative was proposed at the time of the decoupling filing. The company touted decoupling in its filing for its ability to promote energy efficiency and renewable DG but not peak load pricing. Despite an increasingly peaked load profile, PGE didn't propose major rate design innovations in the filing and successively opposed a proposal by commission staff to make some modest pricing reforms. However, the company did agree to a generic hearing to address rate design issues and is currently deploying AMI.

Potomac Electric Power Company (2007-)

The Potomac Electric Power Company ("PEPCO") decoupling plan applies to most customer classes. PEPCO offered TOU pricing to some residential and commercial customers before the institution of decoupling. The filing and the decision did not stress the merits of decoupling in encouraging innovative rate designs. The company proposed reductions in base rate volumetric charges, less seasonal differentiation in rates, and the elimination of an on peak summer demand charge for commercial TOU customers. The Commission denied and/or watered down many of these proposals in the name of gradualism. No innovative new TOU rates were proposed. However, the company has stated its intention to make investments in AMI.

Wisconsin Public Service (2008-2012)

Decoupling covers residential and most commercial customers but not large industrial customers. WPS offered TOU pricing to some residential and business customers before the institution of decoupling in 2008. TOU rate classes will continue. A real time pricing

program will replace the current generation displacement (standby) service for self-generation customers. However, this service is not subject to decoupling.

The decoupling plan also includes the development and implementation of three community based pilot programs that include "innovative rate offerings that increase opportunities for customers to use energy more efficiently". One of these programs will include AMI.

Conclusions

TOU pricing and other forms of peak load pricing are common for electric utilities operating under decoupling plans. This is consistent with the notion that decoupling encourages rate design innovation. While the pervasiveness of peak-load pricing is limited to the availability of AMI, all utilities surveyed seem interested in widespread installation of AMI. Inverted block rates are remarkably common but not universal for small volume customers lacking AMI.

b. We have not identified any available studies or evaluations.

CA-IR-53

Ref: TOU Rates.

a. The Companies assert that there will not be a dilutive effect from decoupling on TOU rates. Please indicate whether a customer's bill will generally increase, decrease, or possibly stay the same under the following scenarios:
   1. If a customer modifies their consumption patterns to shift their load to off-peak times, but their overall consumption remains around the same level.
   2. If a customer modifies their consumption patterns to shift their load to off-peak times and their overall consumption remains around the same level, but due to a company's overall electricity sales being lower, an additional surcharge (i.e., decoupling) is assessed.
   3. If a customer modifies their consumption patterns to shift their load to off-peak times and their overall consumption remains around the same level, but due to a company's large planned plant additions, an additional surcharge is assessed.
   4. If a customer on a TOU schedule cannot modify their consumption patterns to shift their load to off-peak times and their overall consumption remains around the same level.
   5. If a customer on a TOU schedule cannot modify their consumption patterns to shift their load to off-peak times and their overall consumption remains around the same level, but due to a company's overall electricity sales being higher, a credit is assessed.

HECO Companies' Response:

a. As discussed on page 21 of the Joint Final Statement of Position of the HECO Companies and Consumer Advocate, filed in Docket No. 2008-0274, "... [T]he RBA sub-accounts and the RAM Revenue Adjustment will be recovered through a separate per-kWh RBA rate adjustments ..." As a separate line item on customers' bills, the impact of decoupling would have no bearing on the determination or implementation of time-of-use ("TOU") rates, and thus would have no "dilutive" effect. It would be applied to all electric consumption regardless of rate schedule.

The Companies' make the assumption that items 1, 2, and 3 also refer to a customer on a TOU schedule, similar to items 4 and 5. The responses to items 1 through

5 below compare a customer's bill on a TOU rate to the bill on a TOU rate in the scenario described.

1. A customer on a TOU schedule shifting load to off-peak while overall consumption remain at the same level would experience a bill decrease equal to the amount of energy shifted to the off-peak, multiplied by the difference between the on-peak rate and the off-peak rate.
2. The impact on the customer's bill is unknown. This is similar to item 1 above with the exception of an unknown rate level (surcharge) attributable to decoupling. The bill impact would be equal to the amount of energy shifted to the off-peak, multiplied by the difference between the on-peak rate and the off-peak rate, offset by the surcharge rate multiplied by total consumption within the billing period. While it is anticipated that the difference between the on-peak rate and the off-peak rate will be greater than the rate level for a decoupling surcharge, the final bill impact would be dependent upon the volume of electricity consumption transferred from on-peak to off-peak.
3. See the response to item 2 above. It should be noted that the bill impact of a surcharge or credit related to decoupling (due to higher/lower sales or plant additions) will be the same to customers whether they have elected a TOU rate option or whether they have remained on a regular rate schedule, since the amount of the decoupling surcharge or credit would be based on total electricity consumption within the billing period.
4. The customer's bill would remain the same, all else being equal.

5. The TOU customer's bill would decrease by the amount of the credit rate multiplied by the amount of electricity consumed in the billing period.

Life of the Land

LOL-IR-2

Ref: HECO T-1, Page 2, Lines 13 through 17.

"A new awareness of electricity consumption (made possible by the AMI system) will ultimately modify customer behavior - in a similar fashion to drivers, who have purchased automobiles with realtime displays of fuel consumption, which some have coined the 'Prius effect.'" (HECO T-1, 2:13-17)

What percent of Hawaii drivers drive (1) a Prius; (2) an SUV?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies are unable to answer this question directly but an article published in the Washington Post (http://www.washingtonpost.com/wp-dyn/content/article/2008/05/25/AR2008052502764.html) provides useful information that explains the intent of the Hawaiian Electric Companies' original statement regarding the "Prius effect".

LOL-IR-3

Ref: HECO T-1, Page 4, Line 10.

"to begin installing, on a first-come, first-served basis" (HECO T-1, 4:10)

(a) What other prioritization schemes did HECO examine?
(b) Which approach would maximize
    (1) system reliability;
    (2) system security; and
    (3) minimize greenhouse gas emissions?

Hawaiian Electric Companies' Response:

a. Please reference the Hawaiian Electric Companies' response to HSEA-HREA-IR-16 regarding "first-come, first-served basis". The Hawaiian Electric Companies propose to utilize geographic and route-based deployment to minimize installation costs and provide benefits as soon as possible.

b. Generally speaking, approaches which focus on the installation of meters that can provide distribution feeder level information would be useful for system reliability in that voltage data would be available across larger numbers of feeders. Voltage and outage data could also be indicators of potential grid security breaches although this would need to be correlated with other sensing mechanisms such as video feeds. Shorter timeframes for AMI system deployment would provide the highest potential for increased energy efficiency by providing information to customers to make decisions to reduce energy consumption.

LOL-IR-4

Ref: HECO T-1, Page 5, Lines 3 through 7.

"approval of the Advanced Metering Infrastructure Equipment and Services Agreement ("Sensus Agreement") between the Hawaiian Electric Company, Inc. and Sensus Metering Systems, Inc. ("Sensus") including its terms and conditions and a finding that the arrangement is prudent and in the public interest" (HECO T-1, 5:3-7)

How can these contracts be in the public interest if the public can't read them and show an interest in them?

Hawaiian Electric Companies' Response:

The regulatory proceedings for this docket provide the standard mechanism to ensure that the public interest is addressed.

LOL-IR-5

Ref: HECO T-1, Page 5, Lines 19 and 20.

"AMI will improve the accuracy, timeliness and cost efficiency of billing information" (HECO T-1, 5: 19-20)

Do you mean that less loss will occur and therefore ratepayers will be paying for a greater percentage of the total electricity produced?

Hawaiian Electric Companies' Response:

Improved meter accuracy and reduction in energy theft reduce the Companies' unaccounted for energy (included in system losses). This results in an increased level of customer equity (i.e., customer pays for their fair share of the cost of providing electricity).

LOL-IR-6

Ref: HECO T-1, Page 5, Line 21.

"customers will have greater confidence in the bills they receive" (HECO T-1, 5:21)

(a) What makes you think that customers distrust or aren't confident about existing bills?
(b) Should customers not have confidence in existing bills?

Hawaiian Electric Companies' Response:

a. The Hawaiian Electric Companies have no reason to believe that customers are not confident about existing bills. The elimination of the need for estimated bills due to AMI will make it possible to have timely and accurate readings of their actual usage, and receive bills that do not require adjustment. Meter accuracy improvements and energy theft reductions will improve customer equity

b. Customers should have confidence in their bills.

LOL-IR-7

Ref: HECO T-1, Page 5, Lines 21 through 23.

"The availability of recent energy usage information will also empower customers to make more intelligent energy decisions" (HECO T1, 5:21-23)

(a) What is the elasticity of energy use, that is, the differential of use over price.
(b) Are you referring some to other elasticity, and if so, which one and why?

Hawaiian Electric Companies' Response:

a. Price elasticity can be estimated in a variety of ways. One common way to estimate price elasticity is through a regression-based comparison of historical sales and historical prices. The regression coefficients could be interpreted as price elasticities. Regression coefficients for HECO were estimated in Hawaiian Electric's test year 2009 rate case, and are provided in Attachment 1 to this response.

b. The referenced statement does not refer to elasticity. The Hawaiian Electric Companies' statement means that customers who are aware of their energy use will likely be inclined to reduce energy consumption. The extent to which an individual customer works to that end will depend on each individual customer.

Hawaiian Electric Co., Inc.

RESIDENTIAL USE PER CUSTOMER FORECAST MODELS
2008 SHORT-TERM ECONOMETRIC MODEL

Dependent Variable: LOG(RES_RCUSE_ADJ)
Method: Least Squares
Date: 09/16/08 Time: 11:52
Sample: 1997M01 2008M08
Included observations: 140

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.139368	0.482026	0.289130	0.772900
LOG(RES_RCUSE_ADJ(-6))	-0.068387	0.040095	-1.705622	0.090400
LOG(RES_RCUSE_ADJ(-12))	0.606913	0.047466	12.786340	0.000000
LOG(WETBULB_9707)	0.572813	0.077383	7.402362	0.000000
LOG(RES_RPRC_RC(-3))	-0.106043	0.025522	-4.154947	0.000100
MO_YR_TIME	0.000681	0.000092	7.372886	0.000000
M_1	0.038403	0.007773	4.940576	0.000000

R-squared	0.901497	Mean dependent var	6.516890
Adjusted R-squared	0.897053	S.D. dependent var	0.066378
S.E. of regression	0.021298	Akaike info criterion	-4.811730
Sum squared resid	0.060328	Schwarz criterion	-4.664648
Log likelihood	343.8211	Hannan-Quinn criter.	-4.7520
F-statistic	202.869300	Durbin-Watson stat	2.072866

EViews: p sep08 st update.wf1 (res_use_rprc_908upd)

Hawaiian Electric Co., Inc.

RESIDENTIAL USE PER CUSTOMER FORECAST MODELS
2009 LONG-TERM ECONOMETRIC MODEL

Dependent Variable: LOG(RES_USE_ADJ)
Method: Least Squares
Date: 09/16/08 Time: 14:43
Sample (adjusted): 1977 2007
Included observations: 31 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.429038	0.588857	-0.728595	0.472800
LOG(RES_USE_ADJ(-1))	0.881019	0.050501	17.445480	0.000000
LOG(CDD_7807)	0.132138	0.052682	2.508213	0.018700
LOG(YPC_R_HON)	0.096428	0.032006	3.012841	0.005700
LOG(RES_R_PRICE)	-0.031784	0.015013	-2.117087	0.044000

R-squared	0.951733	Mean dependent var	8.949681
Adjusted R-squared	0.944307	S.D. dependent var	0.057044
S.E. of regression	0.013462	Akaike info criterion	-5.631199
Sum squared resid	0.004712	Schwarz criterion	-5.399911
Log likelihood	92.28359	Hannan-Quinn criter.	-5.5558
F-statistic	128.167600	Durbin-Watson stat	2.295156

EViews: p sep08 lt update.wf1 (res_uselt_ypc_908)

Hawaiian Electric Co., Inc.

COMMERCIAL SALES FORECAST MODEL
2008 SHORT-TERM ECONOMETRIC MODEL

Dependent Variable: LOG(COM_RECD_ADJ)
Method: Least Squares
Date: 10/17/08 Time: 16:01
Sample: 1997M01 2008M08
Included observations: 140

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	11.798600	1.097753	10.747950	0.0000
LOG(COM_RECD_ADJ(-1))	-0.198236	0.031884	-6.217410	0.0000
LOG(COM_RECD_ADJ(-4))	0.124973	0.031977	3.908221	0.0001
LOG(COM_RECD_ADJ(-12))	0.248797	0.048278	5.153406	0.0000
LOG(CDD_7807)	0.063114	0.015440	4.087718	0.0001
LOG(WETBULB_9707)	0.758627	0.093494	8.114174	0.0000
LOG(E_NF_HON(-1))	0.138254	0.082175	1.682442	0.0949
MO_YR_TIME	0.000639	0.000103	6.173620	0.0000
M_2	-0.045915	0.006398	-7.176565	0.0000
M_8	0.027969	0.005444	5.138017	0.0000
M_10	0.021499	0.005312	4.047515	0.0001

R-squared	0.959569	Mean dependent var	19.933030
Adjusted R-squared	0.956435	S.D. dependent var	0.070693
S.E. of regression	0.014755	Akaike info criterion	-5.519119
Sum squared resid	0.028086	Schwarz criterion	-5.287989
Log likelihood	397.3383	Hannan-Quinn criter.	-5.4252
F-statistic	306.164200	Durbin-Watson stat	1.887688

EViews: p sep08 st update.wf1 (com_st_enf_908upd)

Hawaiian Electric Co., Inc.

COMMERCIAL SALES FORECAST MODEL
2009 LONG-TERM ECONOMETRIC MODEL

Dependent Variable: LOG(COM_KWH_ADJ)
Method: Least Squares
Date: 09/16/08 Time: 16:48
Sample (adjusted): 1977 2007
Included observations: 31 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	5.470747	1.106582	4.943825	0.0000
LOG(COM_KWH_ADJ(-1))	0.530408	0.074717	7.098868	0.0000
LOG(COM_R_PRICE)	-0.027752	0.009710	-2.857979	0.0085
LOG(CDD_7807)	0.250718	0.038066	6.586343	0.0000
LOG(E_NF_HON)	0.467832	0.091693	5.102176	0.0000
D_96ON	0.044800	0.009268	4.834045	0.0001

R-squared	0.997556	Mean dependent var	22.245870
Adjusted R-squared	0.997067	S.D. dependent var	0.175172
S.E. of regression	0.009487	Akaike info criterion	-6.305885
Sum squared resid	0.002250	Schwarz criterion	-6.028340
Log likelihood	103.7412	Hannan-Quinn criter.	-6.215412
F-statistic	2040.777	Durbin-Watson stat	1.743064

EViews: p sep08 lt update.wf1 (com_lt_enf_908)

LOL-IR-8

Ref: HECO T-1, Page 6, Lines 2 through 4.

"In-home and embedded appliance devices becoming available in the marketplace allow customers to view consumption information almost immediately" (HECO T-1, 6:2-4)

(a) Is it likely that the only those who use embedded appliance devices be the ones who take advantage of the AMI?
(b) Which approach (in-house, meter info) would have a greater impact at reducing demand and peak demand?
(c) Which one is more cost effective for those who would use both?
(d) Which one has a greater impact on ratepayers who choose to do neither?

Hawaiian Electric Companies' Response:

a. No, the Hawaiian Electric Companies' primary mechanism to provide consumption information is through a customer web portal. Devices embedded (built into) in appliances will become available in the consumer market in higher cost models and ultimately flow down to more economical models in the future. Most of the large appliance manufacturers have prototype products and the Hawaiian Electric Companies expect these prototypes to become available during the next five years.

b. The Hawaiian Electric Companies are not aware of any studies of which approach (in-house, meter info) would have a greater impact at reducing demand and peak demand. In-house displays and consumption information provided through a web portal can be used by customers in conjunction with time-of-use ("TOU") rates to reduce peak demand. Higher levels of peak demand reduction are likely with the use of technology to automate the control of a customer's major end-uses (primarily electric water heaters, air-conditioners and clothes dryers).

c. The planned web portal will be the more cost effective means to provide consumption information to customers. For customers who do not have Internet access or who do not feel comfortable using the Internet, the in-home display will be a viable option, especially as the price of these devices drops in the future as the manufacturing scale increases.

d. Providing the capability for customers to monitor their energy use, through a web portal or an in-home display, allows customers with awareness of their level and time of electricity use. Neither of these devices will have a significant impact on the ratepayer, unless they conscientiously utilize the technology. It is not a requirement for a given customer to use either mechanism in order to manage their cost of electricity.

LOL-IR-9

Ref: HECO T-1, Page 6, Lines 5 and 6.

"ability of the AMI Network to control devices or appliances at the customer's premises" (HECO T-1, 6:5-6)

(a) Which appliances will HECO be able to control initially?
(b) Over the current 20-year utility planning horizon, what appliances might HECO be able to control?

Hawaiian Electric Companies' Response:

a. Control of customer loads (and appliances) is beyond the scope of the instant application; however, the AMI network is designed to communicate with load control devices available from Sensus (AMI vendor), including Smart Thermostats. 5-amp pilot devices and 50-amp direct load control switches are currently available for controlling air-conditioning condensing units and electric water heaters and other devices. Sensus is also working with home automation companies to offer a demand response product, which would utilize the AMI network as well as the internet, depending on the type of information that will be conveyed.

b. Over the next 20 years, the Hawaiian Electric Companies envision the availability of smart appliances such as washers, dryers, water heaters, and air-conditioners.

LOL-IR-10

Ref: HECO T-1, Page 6, Lines 7 and 8.

"an important tool to support the integration of increased levels of renewable and distributed generation energy sources into the Companies' grids". (HECO T-1, 6:7-8)

Can AMI be implemented while the percentage of renewables on the grid is
(a) going down;
(b) remaining the same.
(c) Which utilities have implemented AMI while the percentage of renewables was
    (1) increasing
    (2) remaining relatively constant
    (3) decreasing?

Hawaiian Electric Companies' Response:

AMI can be implemented at any time, irrespective of the percentage of renewables on the grid.

AMI can help to increase the percentage of renewables on the grid by providing more data to help manage grid operations.

a. Yes.

b. Yes.

c. The Hawaiian Electric Companies do not have information regaurding the trends of changes in magnitudes of the percentages of renewables at various utilities which are implementing or have implemented AMI.

LOL-IR-11

Ref: HECO T-1, Page 6, Lines 17 and 18.

"The AMI Project proposed by the Hawaiian Electric Companies will help to usher in a clean energy future for Hawaii" (HECO T-1, 6:17-18)

(a) Please define "clean energy";
(b) Have any utilities increased their use of renewables without AMI?
(c) Since HELCO has 6 times the percentage of renewables as HECO, couldn't HECO vastly increase its use of renewables without resorting to AMI?
(d) Which renewable would be able to sharply increase penetration levels due to AMI that they would not achieve without AMI?

Hawaiian Electric Companies' Response:

a. Clean energy can have many definitions but typically include:

   i. Renewable sources of energy (solar, wind, bio-fuels, geothermal, hydro-technologies, etc.)

   ii. Conservation and demand response (building use, grid management, delivery & transportation)

   iii. Enabling technologies (power electronics, storage systems and batteries, sensors & instrumentation, control systems, new materials & manufacturing methods)

   iv. More efficient & effective use of hydrocarbons (hybrid cars and electric cars)

   v. Integrated Systems (sustainable design & integrated clean energy applications)

b. Yes. AMI is not a prerequisite for the increased use of renewables; however, it can help in providing information that is useful to manage grid operations.

c. Each of the three companies is unique in terms of its renewables penetration, grid topology, grid controls and grid operations. There are a number of challenges for each Company in adding more renewable energy. The grid integration studies, discussed in

the response to LOL-IR-1, will provide valuable information pertaining to these barriers. The implementation of AMI will not overcome all these barriers. However, it can provide support by providing grid data and other data down to the customer level. At Hawaiian Electric, the benefits of AMI for providing grid data is higher since it has a lower percentage of substations equipped with Supervisory Control and Data Acquisition (SCADA) than HELCO.

d. The definitive answer for the question of which renewable would be able to sharply increase penetration levels due to AMI that they would not achieve without AMI will not be available until the grid integration studies, discussed in the response to LOL-IR-1, and the Smart Grid Roadmap, discussed in the response to HSEA-HREA-IR-22 are complete.

LOL-IR-12

Ref: HECO T-1, Page 7, Lines 11 through 13.

"Act 155 requires that the energy-efficiency portfolio standards be designed to achieve 4,300 GWh of electricity use reductions statewide by 2030" (HECO T-1, 7: 11-13)

At a recent meeting Estrella Seese stated that the 4300 GWh was determined by using the HECO IRP-3 data ending in 2025 and then pushing it out to 2030 by using the HECO data from 2020-25.

(a) Is this your understanding?
(b) If not, what is your understanding?
(c) Has more recent information shown that the HECO IRP-3 forecast was accurate?
(d) What is the current deviation between that forecast and the current data?

Hawaiian Electric Companies' Response:

a. The Hawaiian Electric Companies did not participate in the development of the 4,300 GWH energy efficiency portfolio standard, and is thus unable to comment on how that goal was derived.

b. See response to part a. above.

c. See response to part a. above. The Hawaiian Electric Companies do not know whether Ms. Seese's use of "IRP-3 data ending in 2025 and then pushing it out to 2030 by using the HECO data from 2020-2025" is in reference to sales and peak forecast data used in HECO IRP-3 or if it is reference to energy efficiency and conservation DSM programs evaluated in IRP-3. Notwithstanding that uncertainty, the Hawaiian Electric Company filed its IRP-4 plan and report with the Commission on September 30, 2008 (Docket 2007-0084), which reports more current sales and peak forecasts as well as more current DSM program projections that updated forecasts and projections used in HECO IRP-3.

d. See response to part c. above.

LOL-IR-13

Ref: HECO T-1, Page 8, Lines 8 through 12.

"AMI also supports many of Hawaii's other and/or related clean energy objectives including the Smart Grid, the greening of transportation, demand response programs, pricing principles and programs, distributed generation, distributed energy storage, net energy metering and investment in infrastructure." (HECO T-1, 8:8-12)

How specifically does AMI support:
(a) distributed generation;
(b) storage;
(c) net energy metering?
(d) Doesn't HECO plan to convert all net energy metering systems to some other program?
(e) How does HECO define "the greening of transportation"?
(f) Are you broadening this docket to consider its impacts on the Smart Grid, the greening of transportation, demand response programs, pricing principles and programs, distributed generation, distributed energy storage, net energy metering and investment in infrastructure?

Hawaiian Electric Companies' Response:

a. AMI can support distribution generation ("DG") by facilitating the measurement of delivered and received power from DG unit(s) while also providing voltage, current and event status information on the grid, which can be used to manage grid operations as the penetration of DG units increases in the future.

b. AMI can support energy storage systems in the same fashion as DG, as explained in part a.

c. AMI already supports net energy metering ("NEM") through the inherent NEM function built into the Sensus AMI metering products.

d. The future of NEM is uncertain at this time, and is still the subject of an open docket (2006-0084) at the Commission. On August 14, 2009, HECO filed a Proposed Plan to Address NEM in Docket 2006-0084, which is provided as Attachment 1 to this response.

e. The greening of transportation can be defined in many ways. Greening transportation could include such things as reducing the need for automobile transportation and promoting environmentally preferable forms of transportation (such as hybrid electric vehicles) and accommodation such as convenient construction or event siting, access to public transportation, alternative fuels, carpooling, and efficient vehicles. Section D.2.a.iv. of the instant Application describes the expected future capabilities for the AMI system to support plug-in electric vehicles.

f. The Companies are not broadening the instant Docket but are pointing out how an investment in AMI can be leveraged beyond the instant application.

August 14, 2009

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street, First Floor
Kekuanaoa Building
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2006-0084 – Net Energy Metering (NEM)
Proposed Plan to Address NEM

Introduction

On July 29, 2009, the Commission issued its Order Denying Extension Request ("Order"), which among other things, denied the Hawaiian Electric Companies' and the Consumer Advocate's request for an extension of time until August 31, 2009, for the Parties to submit a stipulated proposed plan ("Plan") to address the net energy metering ("NEM") agreement, as set forth in the Energy Agreement, in this proceeding.[1] The Order also directs in pertinent part that:

> *The Parties shall file their Plans within fourteen days of the date of this Order. If the commission's decision in Docket No. 2008-0273 changes or affects the Parties' proposed Plans, the commission will allow the Parties to file amended Plans at a later date.*

Order at Ordering Paragraph 2

Pursuant to the Commission's Order, the Hawaiian Electric Companies and the Consumer Advocate respectfully submit their proposed Plan as described below.

---

[1] Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Limited ("MECO") (collectively "Hawaiian Electric Companies"), the Division of Consumer Advocacy of the Department of Consumer Affairs ("Consumer Advocate), Hawaii Renewable Energy Alliance ("HREA"), and Hawaii Solar Energy Association ("HSEA") (collectively known as the "Parties")

Discussion

By Order issued on December 26, 2008, the Commission directed the Parties in this docket to:

> *... submit a stipulated proposed plan for the Parties to address the HECO Companies' and the Consumer Advocate's NEM agreement, as set forth in the Energy Agreement. If the Parties are unable to stipulate, they shall file separate proposed plans by the same date.*

December 26, 2008 Order at Ordering Paragraph 4.

The NEM agreement, as set forth in the Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies ("Energy Agreement"), dated October 20, 2008, states in pertinent part that:

> *The parties are in agreement that there should be no system-wide caps on net energy metering at any of the Hawaiian Electric utilities. Instead, the parties agree to the following:*
>
> - *Distributed generation interconnection will be limited on a per-circuit basis, where generation (including PV, micro wind, internal combustion engines, and net metered generation) feeding into the circuit shall be limited to no more than 15% of peak circuit demand for all distribution level circuits of 12kV or lower;*
> - *New DG requests shall be processed and interconnected on a first-come, first-served basis unless the Commission specifies some other method;*
> - *For those circuits where interconnection requests (particularly for PV) approach the 15% limit, the utility will perform and complete within 60 days after receipt of an interconnection request, a circuit-specific analysis to determine whether the limit can be increased. ****

Section 19, Net Energy Metering (NEM), of the Energy Agreement further states that "NEM currently provides an interim measure to encourage the installation of and pay for renewable energy generated from customer-sited systems, generally PV systems. The parties agree that NEM will be replaced with an appropriate feed-in tariff...."

Since the signing of the Energy Agreement there have been developments that indicate that HELCO (and possibly MECO) is in an advanced stage of renewable energy penetration,

to the point where the NEM agreement as reflected in Section 19 of the Energy Agreement, needs to be assessed and reviewed to ensure circuit reliability, safety, and grid stability. Therefore, the Hawaiian Electric Companies' and Consumer Advocate's proposed Plan endeavors to reasonably and appropriately account for these requirements on a going forward basis.

The Proposed Plan

Section 19 of the Energy Agreement contemplated near term adoption of 15% distribution circuit penetration caps, removal of system-wide NEM limits, and phase out of NEM and replacement with an appropriate feed-in tariff ("FIT"). In Docket No. 2008-0273, the HECO Companies and the Consumer Advocate have proposed a FIT with annual and overall program limits, based on regular assessments of grid reliability, cost, and potential curtailment impacts on existing renewable resources. If NEM is not replaced by such a FIT, NEM system-wide caps should only be modified following appropriate technical assessments and determinations of technical feasibility for each island. The proposed Plan discussed below adopts a 15% per-circuit distributed generation penetration trigger to facilitate the responsible balancing of the need to ensure system reliability and stability with the appropriate management of the NEM program until the first FIT Update is in place.

Shown below are the components of the Hawaiian Electric Companies' and the Consumer Advocate's proposed Plan to address the NEM Agreement as reflected in Section 19 of the Energy Agreement. The Hawaiian Electric Companies and the Consumer Advocate acknowledge and appreciate the Commission's commitment to allow amended Plans at a later date to the extent that any decision in Docket No. 2008-0273 changes or affects the Parties' proposed Plans.

1. Where technically feasible, the Hawaiian Electric Companies will adopt a 15% per circuit distributed generation interconnection limitation designed to be consistent with Section 19 of the Energy Agreement. The Hawaiian Electric Companies will modify their Rule 14.H Distributed Generation Interconnection tariffs as necessary. The Hawaiian Electric Companies and the Consumer Advocate note that the per-circuit distributed generation interconnection limitation referenced in this paragraph will be:

    a. Determined on a distribution circuit-by-distribution circuit basis; and

    b. For each distribution circuit, be limited to an initial interconnection of distributed generation projects, whether on the system side of the meter

or the customer side of the meter, equal to 15% of the peak circuit demand for each distribution circuit.

In determining which projects contribute to the 15% peak circuit demand initial interconnection limitation for each distribution circuit, the Hawaiian Electric Companies and the Consumer Advocate note that any and all distributed generation projects interconnected to an individual distribution circuit, whether it be a NEM project, feed-in tariff project, PV Host project, utility generation project, independent power producer generation project, or other customer-sited distributed generation project, will count towards determining whether the 15% peak distribution circuit threshold has been reached or exceeded. Existing projects already interconnected to the Hawaiian Electric Companies' distribution circuits will be counted in determining whether the 15% peak distribution circuit threshold has been reached or exceeded.

With respect to existing or proposed NEM projects, current eligibility and program design parameters, such as technology, system size (100 kW or less), and true-up requirements, remain unchanged and in effect. The Hawaiian Electric Companies and Consumer Advocate note that the NEM program as currently implemented could be affected by the adoption and implementation of a feed-in tariff in subsequent years.

Timeframe for adopting per circuit distributed generation interconnection limitation[2]: December 31, 2009.

2. As noted above, since the signing of the Energy Agreement in October 2008, there have been developments that indicate that HELCO (and possibly MECO) is in an advanced stage of renewable energy penetration which could affect its ability to integrate more variable renewables without negatively affecting grid stability or existing renewable resources, and which may require that additional resources acquired through any mechanism – including but not limited to NEM, FIT, and customer self-generation – be subject to a system-wide penetration limit. As one example, the Hawaiian Electric Companies provided information to this effect in the course of Docket No. 2008-0273, and in response to TPL-IR-11, described a study being commissioned at the time to examine the dynamic stability impacts of high amounts of PV penetration on the HELCO system. On August 6, 2009, HELCO received the final report from its consultant Electric Power Systems, Inc. ("EPS"), which indicates that under current HELCO system conditions, customer reliability is affected with

[2] Stipulation between the Hawaiian Electric Companies and the Consumer Advocate, and proposed modifications to Rule 14.H will be filed with the Commission for approval.

penetration levels of approximately 2.5 MW or less, for PV having the typical under-frequency inverter trip setting of 59.3 Hz. To the extent that an aggregate amount of 2.5 MW of PV "trips" off line at the 59.3 Hz level, grid frequency will further degrade to 59.0 Hz, the point at which HELCO's under-frequency load-shedding scheme is triggered. The EPS study also illustrates that increasing levels of PV connected with the 59.3 Hz setting requires review of the utility's under-frequency load-shed scheme to ensure it remains satisfactory to halt cascading outages. If the amount of distributed PV lost does not result in additional load shed, it results in a lower minimum frequency. To mitigate this negative impact of distributed PV on system reliability, HELCO has worked with Big Island PV installers since early 2009 in an effort to lower the under-frequency trip settings of PV systems larger than 30 kW to 57.0 Hz, in accordance with IEEE Standard 1547. While larger installed systems have this capability, other large system and most of the 30kW or less installed systems do not have the capability to lower their IEEE1547 trip settings to 57.0 Hz. Accordingly, HELCO estimates that the 2.5 MW threshold for resources with the 59.3 Hz trip setting described in the EPS report has already been reached or exceeded on the HELCO system.[3]

As such, the provision to remove system-wide caps reflected in Section 19 of the Energy Agreement needs to be assessed and reviewed in order to ensure circuit reliability, safety, and grid stability. Consequently, the Hawaiian Electric Companies will conduct an assessment to determine how the removal of system-wide caps and adoption of per-circuit distributed generation interconnection limitations described in Paragraph 1, above, impacts the Hawaiian Electric Companies' systems, including, but not limited to, the reliability and stability of each company's system. To the extent that concerns are identified such as in the EPS report, the Hawaiian Electric Companies will also assess potential mitigation measures to be taken by the utility and PV installers that would allow a greater level of PV development.

Timeframe for completing assessment of removal of system-wide caps: November/December 2009.

3. As discussed above, the Hawaiian Electric Companies and the Consumer Advocate propose a 15% peak circuit demand initial interconnection limitation determined on a distribution circuit-by-distribution circuit basis. To assist interested parties in planning and developing various projects that could be interconnected to the Hawaiian Electric, HELCO, or MECO system at the

[3] The EPS report is attached hereto as Attachment 1.

distribution circuit level, the Hawaiian Electric Companies propose the development of Locational Value Maps specific to each Hawaiian Electric Company.[4]

Timeframe for completion: December 2009.

4. The Hawaiian Electric Companies and the Consumer Advocate are aware that the assessment proposed in Paragraph 2, above, has the possibility of affecting the manner in which distributed generation projects are interconnected to the Hawaiian Electric Companies' systems. Upon the completion of the

---

[4] The Hawaiian Electric Companies note that:

a. The specificity and general usefulness of the distribution circuit peak circuit demand information provided to interested parties seeking to develop a project that could be interconnected to the Hawaiian Electric Companies' systems will depend upon whether a proposed project's location can be determined by the Hawaiian Electric Companies with a high degree of specificity (e.g., knowing the Tax Map Key number for the site of the proposed project, etc.).

b. The distribution circuit peak circuit demand information provided to interested parties seeking to develop a project that could be interconnected to the Hawaiian Electric Companies' systems will reflect peak circuit demand information taken at a specific point in time. Consequently, interested parties seeking to develop a project that could be interconnected to the Hawaiian Electric Companies' systems should be aware that distribution circuit peak circuit demand can, and will, change as customer usage of electricity on a particular distribution circuit changes. Put another way, interconnection availability on any particular distribution circuit can, and will change, as customer usage on the distribution circuit changes. In addition, the Companies perform regular changes to the segmentation of individual distribution circuits to balance loads on distribution circuits which will also impact the peak circuit demand for individual circuits. As such, interested parties seeking to develop a project that could be interconnected to the Hawaiian Electric Companies' system should be aware that the ability to interconnect projects consistent with the 15% peak circuit demand interconnection limitation proposed above can, and will, change on a dynamic basis. Interested project developers should consult with the Hawaiian Electric Companies regularly to receive updates on distribution circuit peak circuit demand.

c. Interested parties seeking to develop a project that could be interconnected to the Hawaiian Electric Companies' system should contact the Hawaiian Electric Companies if the interested parties wish to inquire as to what distribution circuits currently have interconnection availability under the per circuit interconnection limitation described in Paragraph 1, above. The Hawaiian Electric Companies will endeavor to work with the Parties to this docket to develop a process whereby interested developers can contact the Hawaiian Electric Companies to receive information or updates as to what distribution circuits currently have interconnection availability under the per circuit interconnection limitation set forth in Section 19 of the Energy Agreement, as implemented by Paragraph 1, above.

assessment proposed in Paragraph 2, above, the Hawaiian Electric Companies intend to re-examine their tariff rules to bring the relevant rules into conformity with the assessment, if necessary.

Timeframe for completion: As necessary.

Sincerely,

Catherine P. Awakuni
Division of Consumer Advocacy

Darcy Endo-Omoto
Hawaiian Electric Company, Inc.
Hawaii Electric Light Company, Inc.
Maui Electric Company, Limited

Attachment

cc: Division of Consumer Advocacy
Warren Bollmeier II
Rick Reed/Mark Duda
Erik Kvam
Kent Morihara/Kris Nakagawa

HELCO Maximum Penetration of Distributed Generation Study

EPS Job #08-0440

Prepared for:

Hawaii Electric Light Company, Inc.
PO Box 1027
Hilo, Hawaii 96721-1027

Prepared by:
Dr. James W. Cote, P.E.
Kelly Ridge

ELECTRIC POWER SYSTEMS, INC.
4020 148th Ave. N.E. Suite C
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Final Report

August 6, 2009

SUMMARY OF CHANGES

Revision Number	Revision Date	Revision Description
1	04-03-2009	*Issued for Review*
2	08-06-2009	Issued Final Revision

TABLE OF CONTENTS

1 Executive Summary

Electric Power Systems, Inc. (EPS) was asked to evaluate the effect of distributed generation penetration in the Hawaii Electric Light Company (HELCO) system. To perform this study EPS created a set of six base cases that highlighted HELCOs most constrained dispatch scenarios. Several variables were considered to accurately test the HELCO system. Base cases ranged from the daily minimum to the daily maximum loading level. EPS attempted to dispatch the minimum required spinning reserve for each base case. The minimum steam requirement, which was defined in previous studies by EPS, and the amount of As Available generation were additional constraints that EPS considered when creating the base cases.

The scope of this study called for analyzing the impact of distributed generation penetration within the HELCO system. EPS modeled the Distributed Generation (DG) as a constant power source. While there are several types of DG present in the HELCO system, EPS generalized the types and refers to all DG in this report at photovoltaic generation (PV).

Two types of dynamic stability analysis were run to determine the impact of PV penetration on the system. The first set of stability cases were used to evaluate the system response to unit trips as PV is incrementally added. In the second set of stability cases, EPS attempted to determine the amount of PV that could be added to the system such that for certain unit outages, the PV would cause under-frequency load shedding during a trip of generation.

EPS found that under-frequency load shedding (UFLS) and the amount of system spinning reserve available are two major factors in how PV penetration affects HELCO system dynamic response. The following report details the procedures and results of this study.

2 Introduction

HELCO is experiencing an increasing amount of distributed generation projects that want to interconnect with their system. EPS was tasked to perform a study of the existing and future distributed generation interconnected to the HELCO system, determine any adverse impact of the generation, and, if possible, determine the maximum allowable amount of distributed generation.

HELCO and EPS determined that the most effective way to analyze the impact of photovoltaic generation sources (PV) on the system would be evaluate the system response due to generation unit trips and compare system response at varying amounts of interconnected PV. EPS focused primarily on the effects of PV penetration on the system frequency response and on the UFLS scheme in place. The existing HELCO UFLS scheme and a proposed EPS UFLS scheme were both used in this study.

This study assumes that all the PV sources are in compliance with IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems.

3 Studies

3.1 Power Flow Base Cases

EPS created six power flow bases cases for this study. The six cases range from the system minimum to maximum loading levels. Table 1 below lists the seix different base case dispatches that were studied.

Table 1 – Dispatches for Power Flow Base Cases

Case Number	1	2	3	4	5	6
Unit						
Hill 6		17.5	17.5		17.5	
Hill 5	8.0	10.5	10.5	10.5	10.5	10.5
Puna Steam	6.0	14.1	14.1	11.1	14.1	11.1
PGV	27.0	27.0	27.0	27.0	27.0	27.0
Keahole 1CTCC	27.3	27.3	27.3	27.3	27.3	27.3
HEP 1CTCC	16.0	28.5	28.5	28.5	28.5	28.5
Keahole second CT - 2CTCC				29.9	29.9	29.9
HEP second CT additional - 2CTCC				31.5	31.5	31.5
As Availables	low	low	high	low	low	high
Wind						
HRD	2.0	2.0	10.0	2.0	2.0	10.0
Apollo	4.5	4.5	20.0	4.5	4.5	20.0
Hydro						
WAIAU 1			0.4			
WAIAU 2			0.8			
PUUEO 3			0.8			
PUUEO 4			3.0			
WRHPC 1			3.0			
WRHPC 2			3.0			
Totals:	90.8	131.4	165.8	172.3	192.8	195.8

EPS chose the six cases in Table 1 to represent HELCO's more constrained operating conditions. Case 1 is the HELCO system minimum load case, and case 6 is the HELCO's peak load case. EPS also looked at four more cases with load levels falling in between the minimum and maximum cases. EPS varied the amount of As Available generation as well as the number of steam generators online to fully test the operating limits of the HELCO system during this study. In cases 1, 4, and 6, the steam unit, Hill 6, was taken offline. The HELCO system has a

minimum steam generation requirement of two steam units, and taking Hill 6 offline in the above cases leaves only the Hill 5 and Puna steam generators online. The amount of As Available generation online has been shown in previous studies to affect the dynamic stability of the HELCO system. Because of this, cases with both high and low As Availables were studied.

In each base case, EPS attempted to maintain a minimum of 6 MW of required reserve generation, or spin, online. The 6 MW of spin is typically carried on two out of the following three steam units in the HELCO system, Hill 6, Hill 5, and Puna Steam. Base Case 1 is the minimum load case and due to minimum dispatch constraints carries more spinning reserve than the other five base cases, which have the minimum required spin of 6 MW.

3.2 Dynamic Stability Runs

EPS initially selected four different unit trip scenarios, these were unit trips of Hill 5, Hill 6, Puna Steam, and HEP CT 1. The four unit trip cases were run on each of the six power flow base cases, creating a total of 24 dynamic stability runs. These 24 base cases were then re-evaluated with 2 MW, 4 MW, and 6.5 MW of PV added to each of the dispatches.

A maximum PV penetration value of 6.5 MW was chosen based the minimum amount of As Available generation online in Base Cases 1, 2, 4, and 5, and based on the study results. When PV was added to the base cases, the As Available generation was backed off primarily because these units do not carry spin. Therefore, the 6 MW of required system spin was maintained when the PV generation was added. An under-frequency trip point of 59.3 Hz for the PV generation was assumed and modeled based on IEEE Standard 1547, Table 2 – *Interconnection system response to abnormal frequencies.*

The PV generation was modeled as a constant power injection with an under-frequency trip point of 59.3 Hz. Five equivalent PV generation models were added to the HELCO database. EPS placed the five PV models geographically across the island in a uniform distriubtion. From previous studies completed for HELCO, EPS has found that the HELCO system frequency is basically uniform across the island during unit trips, and therefore the exact placement of the PV models was not a critical factor in this study.

EPS ran simulations with and without the PV generation and determined the minimum system frequency reached in each case and plotted that against the different PV penetration levels. Figures 1 and 2 each show the amount of PV generation on the x-axis and the minimum transient frequency on the y-axis, for each of the six base case power flows, for the trip of the Puna Steam unit. Figure 1 shows the results with the HELCO UFLS scheme in place, and Figure 2 shows the results for the proposed EPS UFLS scheme. The unit trip simulations are unit breaker open events resulting in an immediate loss of generation in the system, not a unit ramp down event. The minimum frequency is the transient frequency dip, and does not represent the settling frequency or the ultimate frequency one would expect based on the unit droop characteristics.

Figure 1 - Minimum Frequency vs. PV Penetration

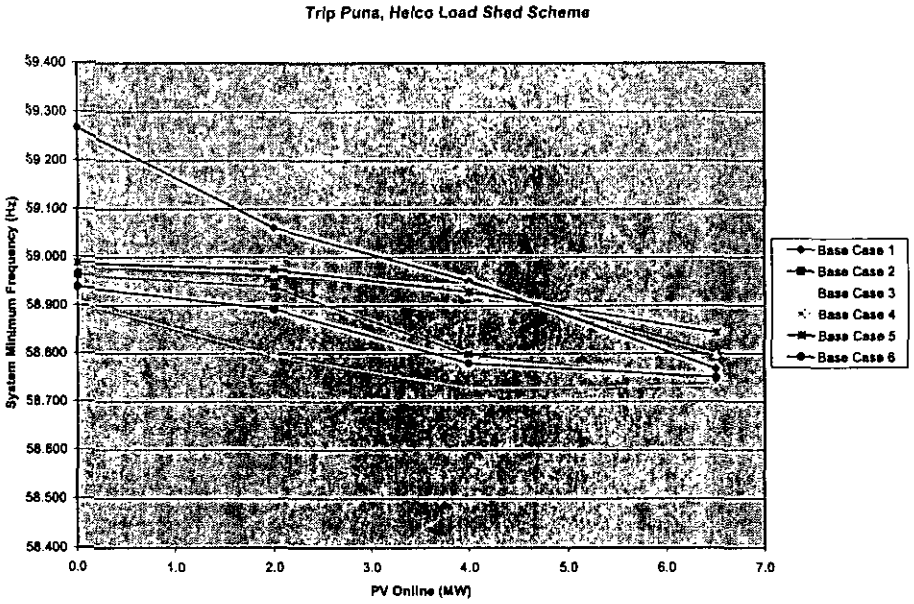
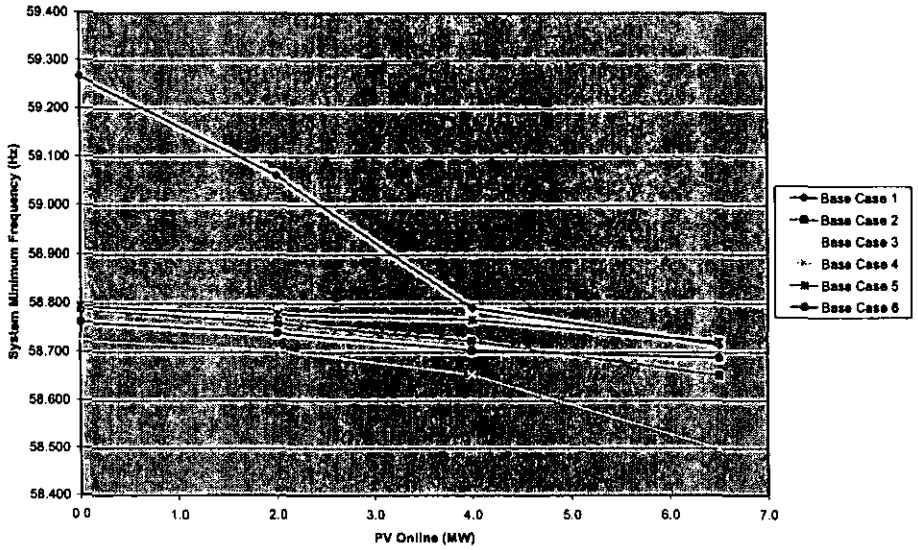


Figure 2 – Minimum Frequency vs. PV Penetration



In both Figure 1 and 2, case 1 has a better system response due to the Puna Steam unit trip when there is either 0 MW to 2 MW of PV online, as compared to the other cases. This is

because base case 1 has less generation output for Puna Steam than in the other base cases. Additionally, more spinning reserve is online in base case 1 than in the other base cases, and the first stage of load shedding is not reached until PV penetration is at 4 MW. This is also true for the trip of Hill 5 in Case 1, where Hill 5 is at a lower output than in the other cases.

The transient stability plots for all four unit trip scenarios for both the HELCO and EPS load shed schemes are in Appendix A. The unit trip cases found in Appendix A highlight the effect that spinning reserve and under-frequency load shedding have on PV penetration. For all of the cases with the exception of base case 1, all four unit trip scenarios resulted in stage 1 and / or stage 2 load shedding before PV is added to the system. In most cases, the amount of load shed in stages 1 or 2 was sufficient to immediately stop the frequency decay. As a result, the amount of PV that can be added to the system for these cases, without any additional frequency decay, is equal to the amount of "extra" load shedding. The extra amount of UFLS is the amount of load in excess of the required amount to stop the frequency decay. Therefore, these results will show a very slight decrease in frequency when PV is added, until we reach the point where additional load shed is required. The load shedding effects actually overwhelm the effect of adding PV generation to the system, up to the point where the load shedding becomes insufficient.

When PV was added, the effect on the system was a slight decrease in the minimum frequency. Load shedding does not occur in the Base Case 1, where no PV is added, for either the Puna Steam or Hill 5 unit trip. When PV is added to these cases a sharp decrease in the system minimum frequency is observed. This shows that when stage 1 under-frequency load shedding has already occurred due to a disturbance, the system is less sensitive to the addition of PV generation.

Table 2 shows the load shed during the 6 different cases for the trip of unit Hill 5 with 6.5 MW of PV online. With the HELCO UFLS Scheme in place, cases 2 through 5 go into stage 2 of load shedding. The EPS load shed scheme only reaches stage 1, and a lower overall total of load is shed with the EPS Scheme in place.

Table 2 – Stage 1 Load Shedding for Trip of Hill 5, with 6.5 MW PV Online

Base Case	HELCO UFLS Scheme		EPS UFLS Scheme	
	Stage 1, 59.0 Hz	Stage 2, 58.8 Hz	Stage 1, 58.8 Hz	Stage 2, 58.7 Hz
1	3.84 MW		7.82 MW	
2	5.45 MW	9.44 MW	16.61 MW	
3	6.71 MW	11.45 MW	13.46 MW	
4	7.45 MW	12.46 MW	14.45 MW	
5	8.16 MW	13.34 MW	15.77 MW	
6	8.55 MW		16.53 MW	

The original analytical approach discussed by HELCO and EPS was the evaluation of the unit trips described above. These results clearly indicate an interaction between the amount of PV generation, the size of the unit trip, and the UFLS settings and load shed amounts. In particular, when load shedding occurs, the amount of load shed is normally larger than the amount of tripped generation. When this occurs, the frequency will stop decreasing and will immediately increase. This occurs as long as the amount of load shed exceeds the amount of lost

generation. Therefore, the amount of PV generation tripped at 59.3 Hz does not have any significant impact on the minimum frequency, until the amount of PV generation plus the amount of lost generation due to the trip exceeds the first stage of load shedding. Above this amount of PV, the frequency minimum will decrease measurably with increasing PV. Because of the interaction between load shedding and the amount of PV generation, an alternate analytical approach was considered, as described below.

Alternate Analysis

An alternative method to quantify the impact that PV generation has on the HELCO system is by determining the amount of PV that would cause the first amount of under-frequency load shedding, assuming that no load shedding would occur without the presence of PV. HELCO's first stage of load shedding occurs when the system frequency decreases below 59.0 Hz. The under-frequency trip point for the PV generation is 59.3 Hz. With PV added to the HELCO system, any disturbance that causes the system frequency to dip below 59.3 MW will now result in the loss of PV generation. It was our goal to determine the maximum amount of PV generation that could be added such that a case without PV generation that would reach a frequency of 59.3 Hz will now reach a minimum frequency around 59.0 Hz. Any additional PV generation will cause load shedding for the same disturbance.

For this analysis, EPS first chose three base cases that would encompass the operating boundaries of the HELCO system. The cases chosen were Base Cases 1, 3, and 6. The dispatches corresponding to these cases are in Table 1. EPS then determined the amount of generation for each of these base cases that needed to be tripped to result in a minimum transient system frequency of 59.3 Hz. PV was then added incrementally to each of the cases and the generation trip re-run until the PV amount was found that corresponded with the minimum system frequency just above 59.0 Hz. Table 3 below details these amounts for each of the base cases.

Table 3 – PV for no UFLS, HELCO UFLS Scheme

Base Case	Unit trip (MW) to reach 59.3 Hz	PV (MW) added to get to 59.0 Hz
1	6.0 MW	2.5 MW
3	9.8 MW	2 MW
6	6.65 MW	< 1 MW

For base case 3, the amount of generation tripped to get to 59.3 Hz was 9.8 MW. As available generation was tripped (9 MW of Apollo wind and 0.8 MW at Puueo 3 Hydro) thereby not affecting the system spinning reserve. EPS then added PV to the base case and found that 2 MW of PV added to the system combined with the 9.8 MW generation trip resulted in the system frequency dipping close to (but not below) 59.0 Hz. This means that for the medium load level, and corresponding dispatch of base case 3, there is a maximum limit of 2 MW of PV that can be added to the system, otherwise a unit trip of 9.8 MW will cause under-frequency load shedding. Recall that this same amount of lost generation, 9.8 MW, would not cause load shedding if there was no PV generation online. Figures 3 and 4 show base case 3 with no PV added and base case 3 with 2 MW of PV added.

Figure 3 – Base Case 3, Tripped 9.8 MW of Generation, no PV

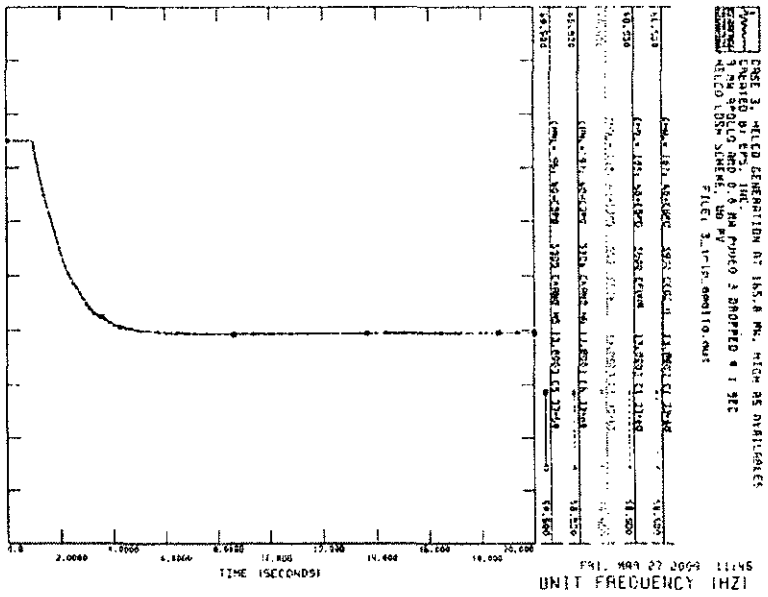
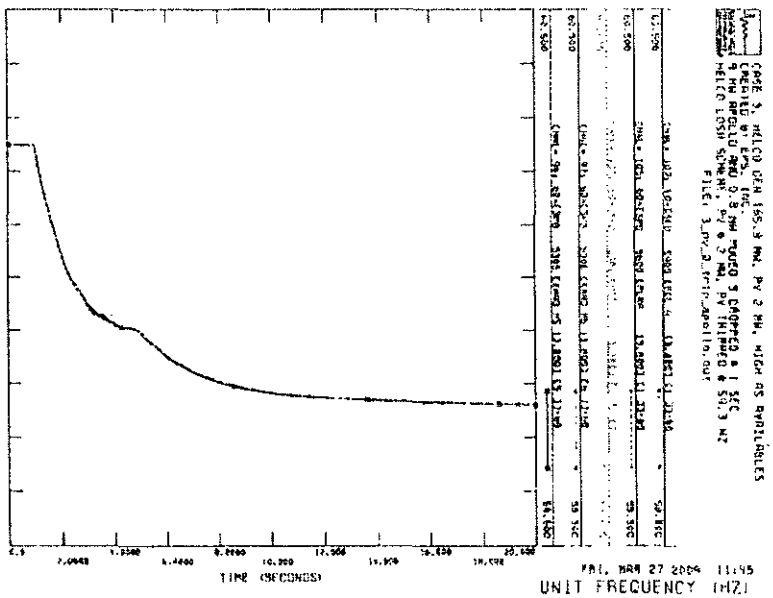


Figure 4 – Base Case 3, Tripped 9.8 MW of Generation, 2 MW PV added



Another factor that impacts the HELCO system response to a disturbance is the governor limits of Hill 6. The dynamic model for the Hill 6 governor within PSS/E (the transient stability software) has a maximum power output that is greater than the maximum output used to calculate the amount of spinning reserve that Hill 6 can contribute. The maximum power output for the Hill 6 governor is 23.0 MW, corresponding to the unit capacity but larger than the ECO or LFC limits in AGC for the unit. This provides an extra 2.5 MW of spin in the transient stability simulation when an under-frequency event occurs. Therefore, in cases with Hill 6 online, the system has a better response to a disturbance because there is more real spin than the minimum requirement of 6 MW of spin. In Table 3, case 3 has Hill 6 online, and cases 1 and 6 do not. Case 3 can withstand a 9.8 MW generation trip and just reach 59.3 Hz, whereas the other two cases can only withstand about a 6 MW generation trip. The extra 2.5 MW of actual spin on Hill 6 in case 3 provides for a better system response.

In Table 3, case 6 is shown as being able to accommodate less than 1 MW of PV added to the system. This case highlights the effect that the minimum spinning reserve has on the system during a generation trip. In case 6, there is 6 MW of spin shared between Hill 5 and Puna Steam. When 6.65 MW of generation is tripped the system recovers and settles to a frequency of 59.3 Hz. However there is very little rebound in the frequency after the minimum is reached. When a small amount of PV is added, such as 1 MW, the system has no spinning reserve to recover from the extra loss of even 1 MW. When generation unit trips occur, close in size to the amount of spinning reserve online, the system becomes very sensitive to any further loss of generation.

The transient stability plots for Base Cases 1, 3, and 6 are attached in Appendix B.

4 Discussion on System Bias

Most of the time, HELCO relies on three units to provide the required system spinning reserve. These units are Hill 5, Hill 6, and Puna Steam. The maximum combined output of these three units is about 47.9 MW. The turbine / governor droop value for each unit is approximately 4%, or 2.4 Hz for a 100% change in unit output. If the three steam units are the only units capable of responding with additional generation during an under-frequency event, then the system bias in the raise direction would be about 47.9 MW per 2.4 Hz. This is equivalent to about 20.0 MW/Hz, or roughly 2.0 MW/0.1 Hz. Note however that this calculation is based on the steady state droop characteristic of the governors, not the transient under-frequency response of the turbine / governors. The transient frequency excursion will be larger, and can be much larger than the expected frequency excursion calculated from the system bias value.

A critical aspect of the impact of PV generation on the HELCO system is the relationship between the PV under-frequency trip point of 59.3 Hz and the first HELCO under-frequency load shed point of 59.0 Hz. These two frequency points are important during the transient response of the system to a disturbance.

If the system bias value of 2.0 MW / 0.1 Hz was a valid measure of the frequency excursion due to a loss of generation, the 0.3 Hz range (59.3 – 59.0 Hz) should be equivalent to 6 MW of additional generation. However, the system bias does not accurately describe the transient frequency dip due to a loss of generation.

Throughout this study, EPS found that using the system bias to estimate the maximum allowable amount of PV is too high. The maximum PV value of 6.0 MW is calculated using a system bias value based on the system responding along the governor droop line to a disturbance. In reality, governors will restore the system frequency to a point determined by the droop line after typically tens of seconds following a disturbance. The minimum frequency due to a disturbance usually occurs in the transient time frame (normally only a couple of seconds) as the turbine governors are beginning to respond but before the governors completely react to the outage. This explains why the maximum PV values found in Table 3 are much smaller than the 6.0 MW value based on system bias and droop characteristics.

5 Conclusions

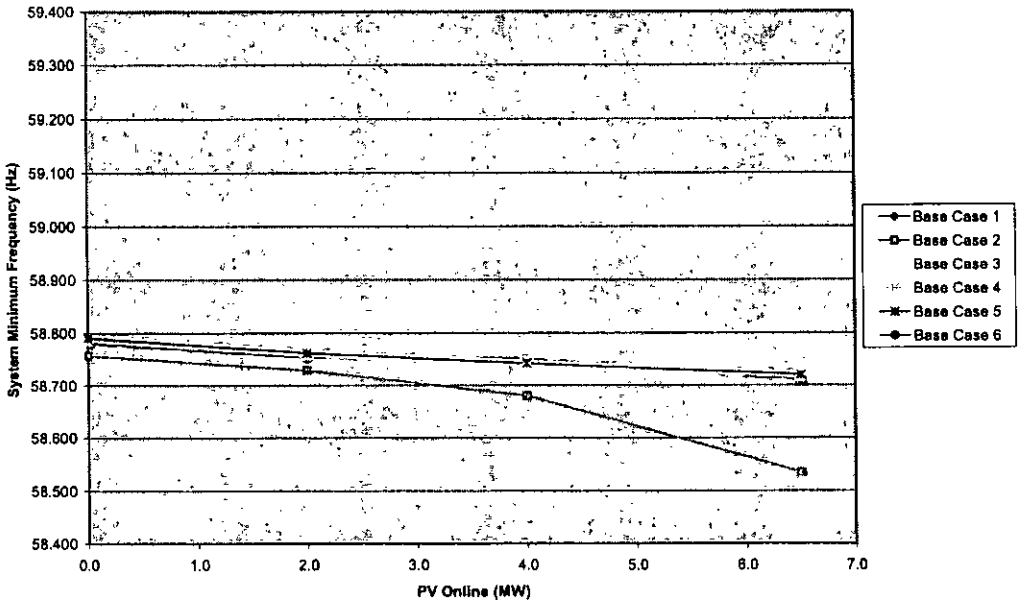
EPS analyzed the effect that PV penetration has on the HELCO system by evaluating the system response to unit trips with varied levels of PV online, as well as determining the PV level that causes the HELCO system to go into UFLS.

The first evaluation used 4 different unit trip scenarios and a range of zero to 6.5 MW of PV online. The resulting plots, found in Appendix A, show that if the system reaches the first stage of UFLS due to a unit trip and no PV is online, the addition of PV has a more subtle effect on system minimum frequency decay. In the base cases that a unit trip does not cause UFLS, however, the addition of PV causes a steep decline in the system minimum frequency. UFLS desensitizes the HELCO system response to the addition of PV up to the point of the next stage of load shedding.

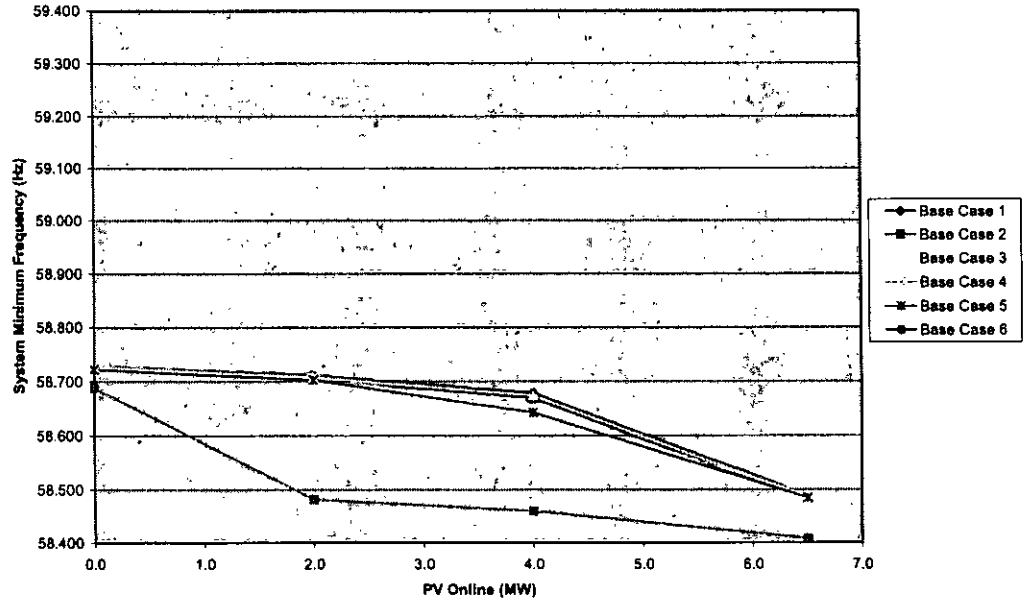
The second set of simulations were used to obtain an amount of PV generation that would cause the HELCO system to go into UFLS when it would otherwise not shed load. EPS found that the minimum frequency reached during a trip of generation was greatly affected by the amount of actual spinning reserve online. This is apparent especially when Hill 6 is online, providing an extra 2.5 MW of spinning reserve due to a difference in unit capacity versus ECO capacity. During this analysis, the amount of PV added to the system that would cause UFLS was consistently around 2 to 2.5 MW. This analysis highlighted the result that the minimum system frequency that occurs during a disturbance appears during the transient time frame, before the governors fully respond along their droop line. Therefore, the affects of droop settings and even AGC are not very pertinent to preventing UFLS when the amount of spinning reserve is small.

Appendix A – Minimum Frequency vs. PV Penetration Plot

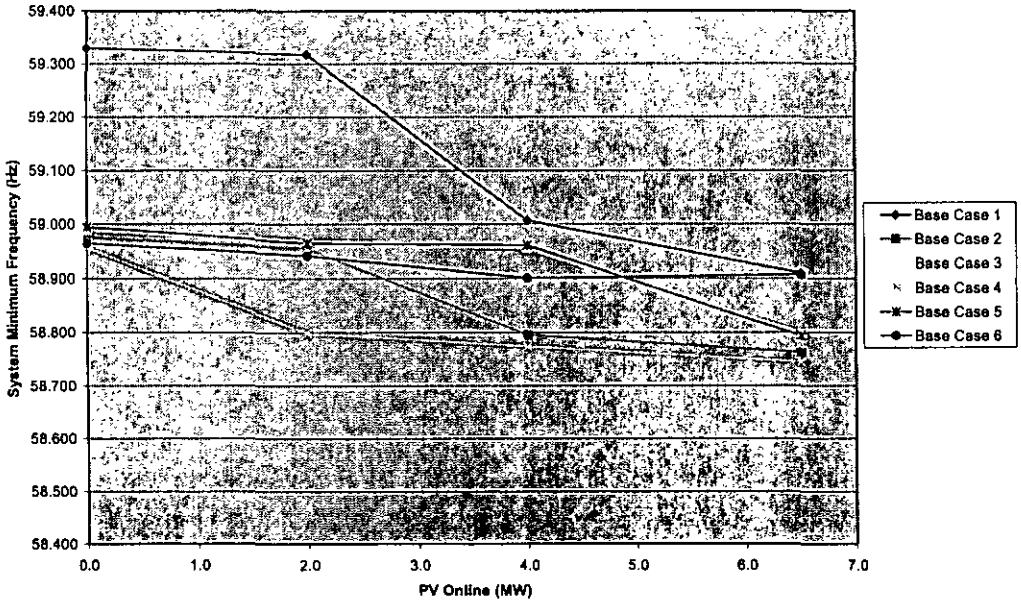
Trip Unit Hill 6, Helco Load Shed Scheme



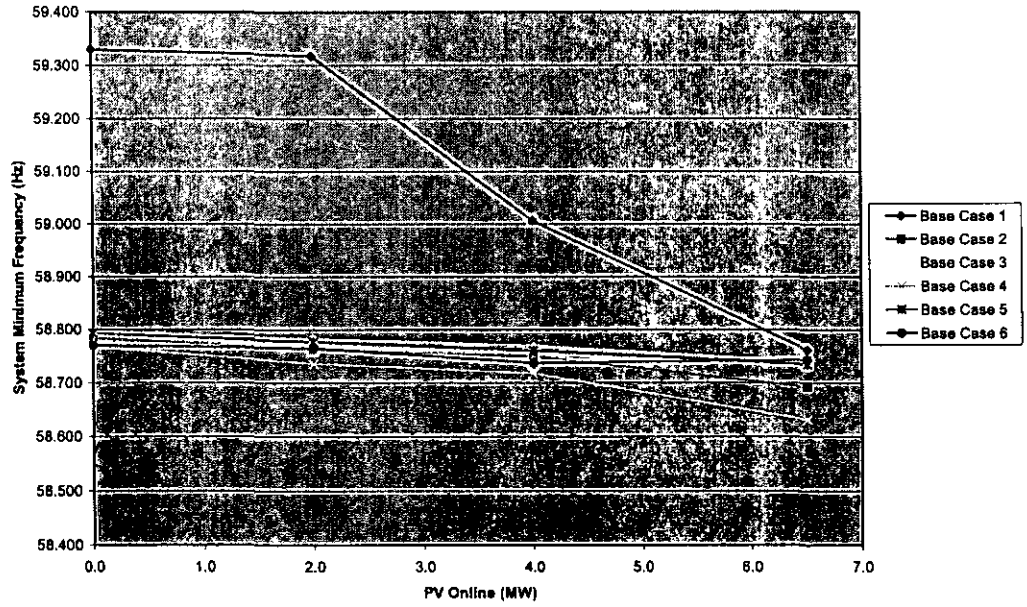
Trip Unit Hill 6, EPS Load Shed Scheme



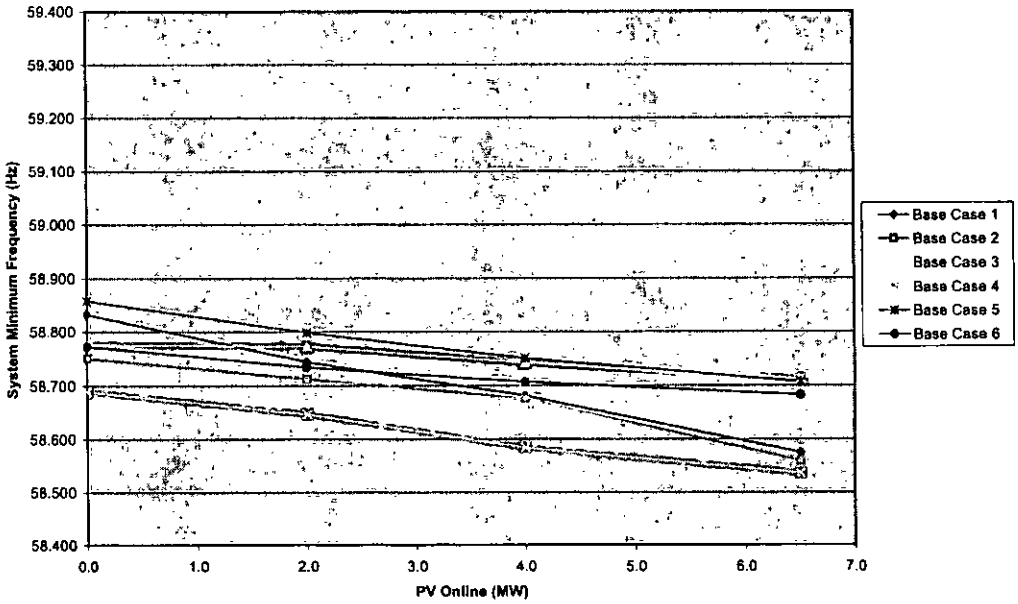
Trip Unit Hill 5, Helco Load Shed Scheme



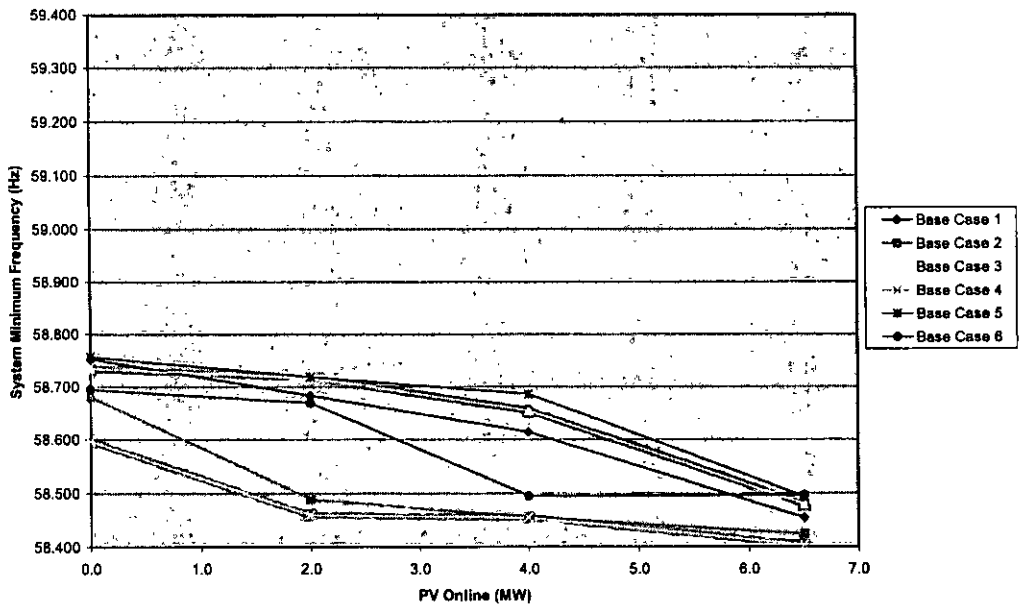
Trip Unit Hill 5, EPS Load Shed Scheme



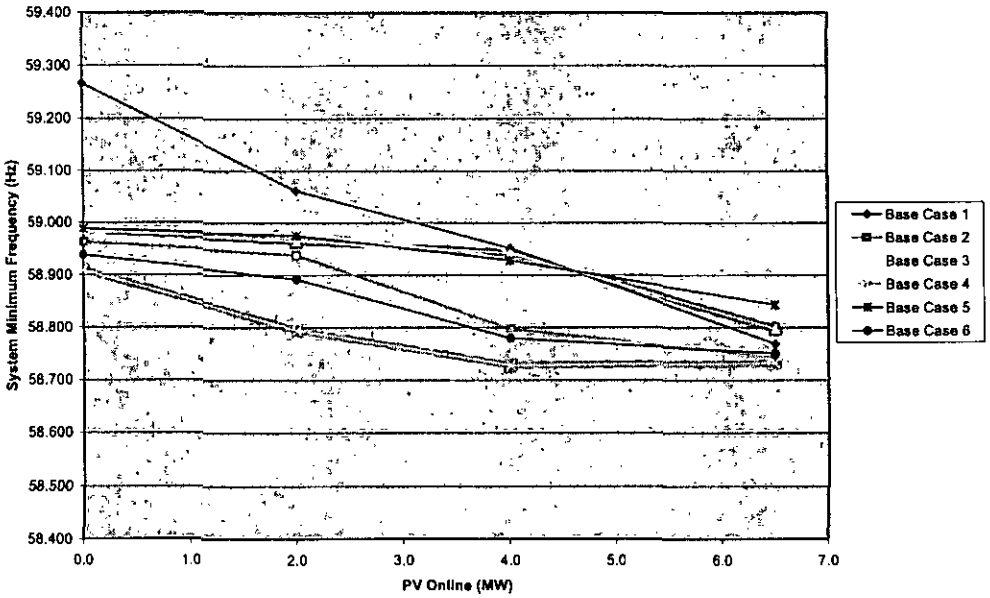
Trip HEP, Helco Load Shed Scheme



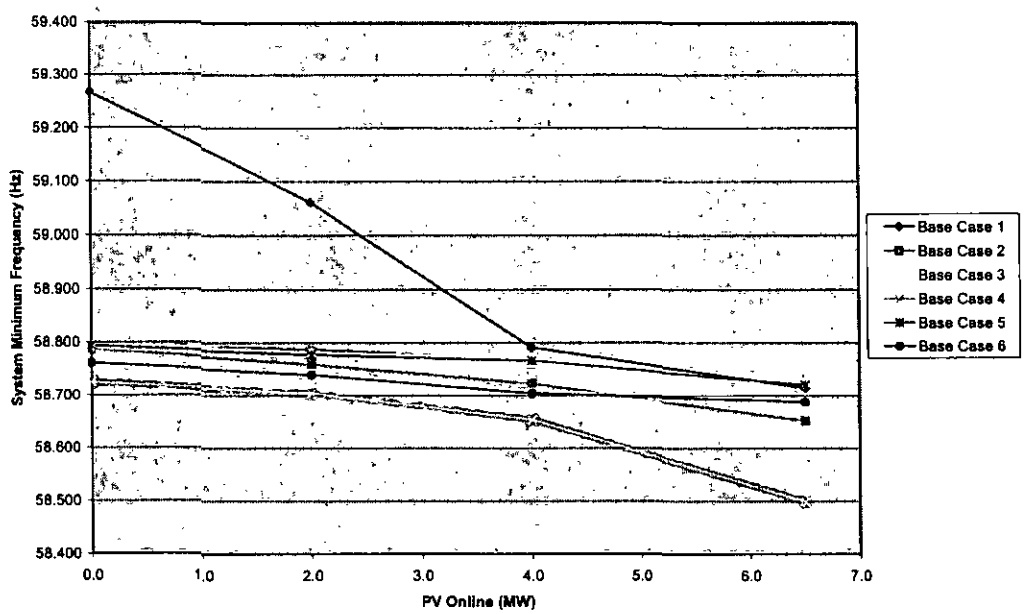
Trip HEP, EPS Load Shed Scheme



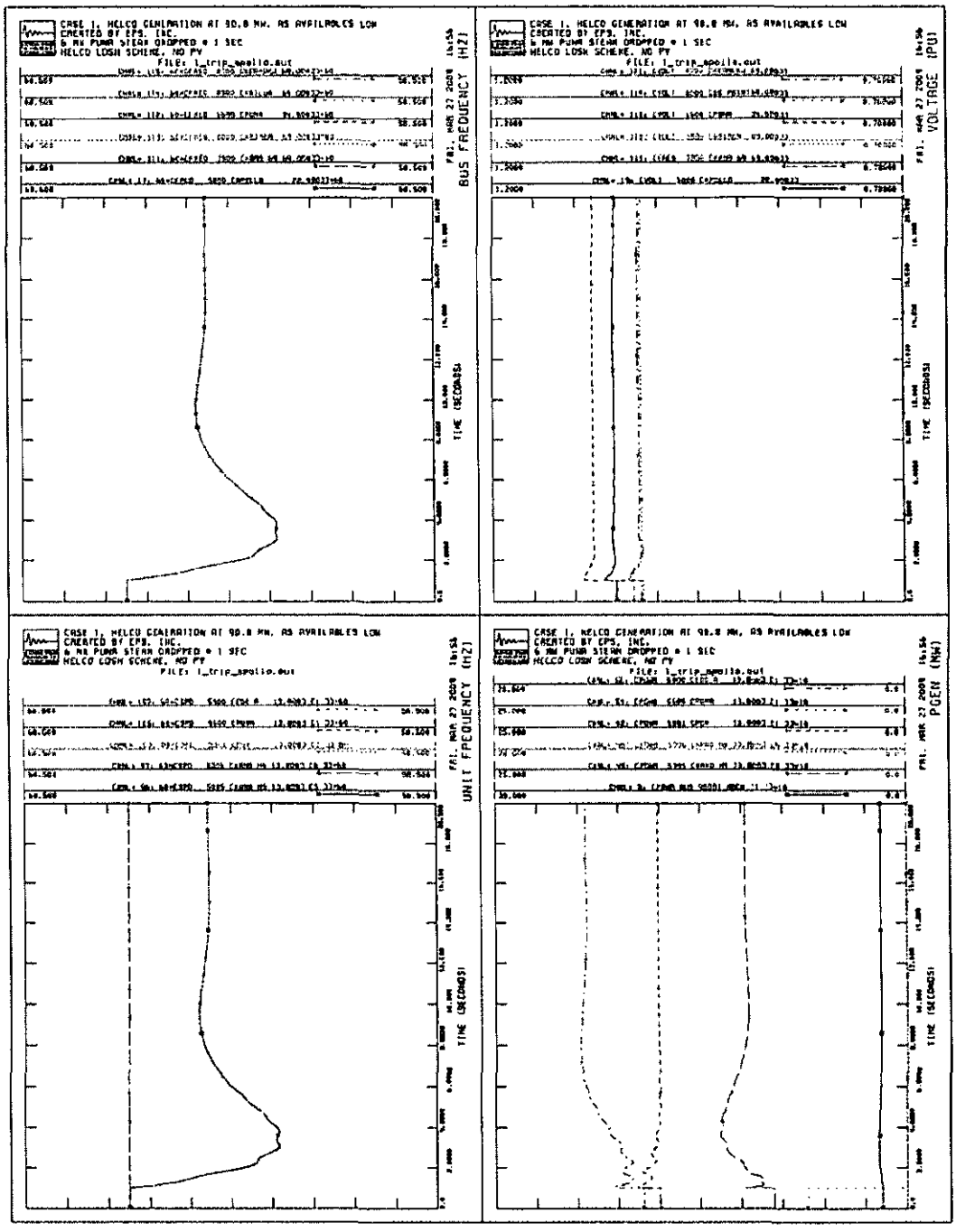
Trip Puna, Helco Load Shed Scheme

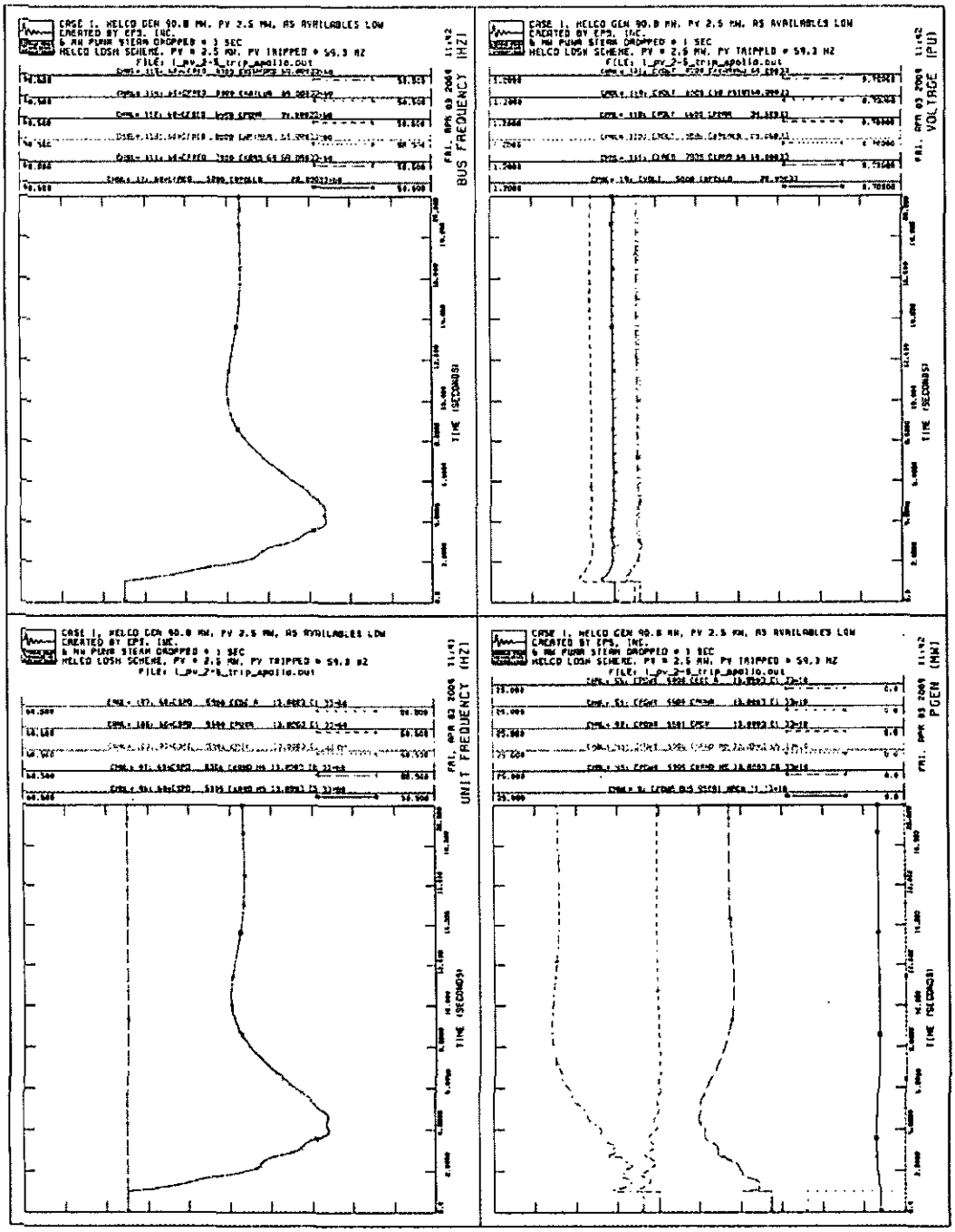


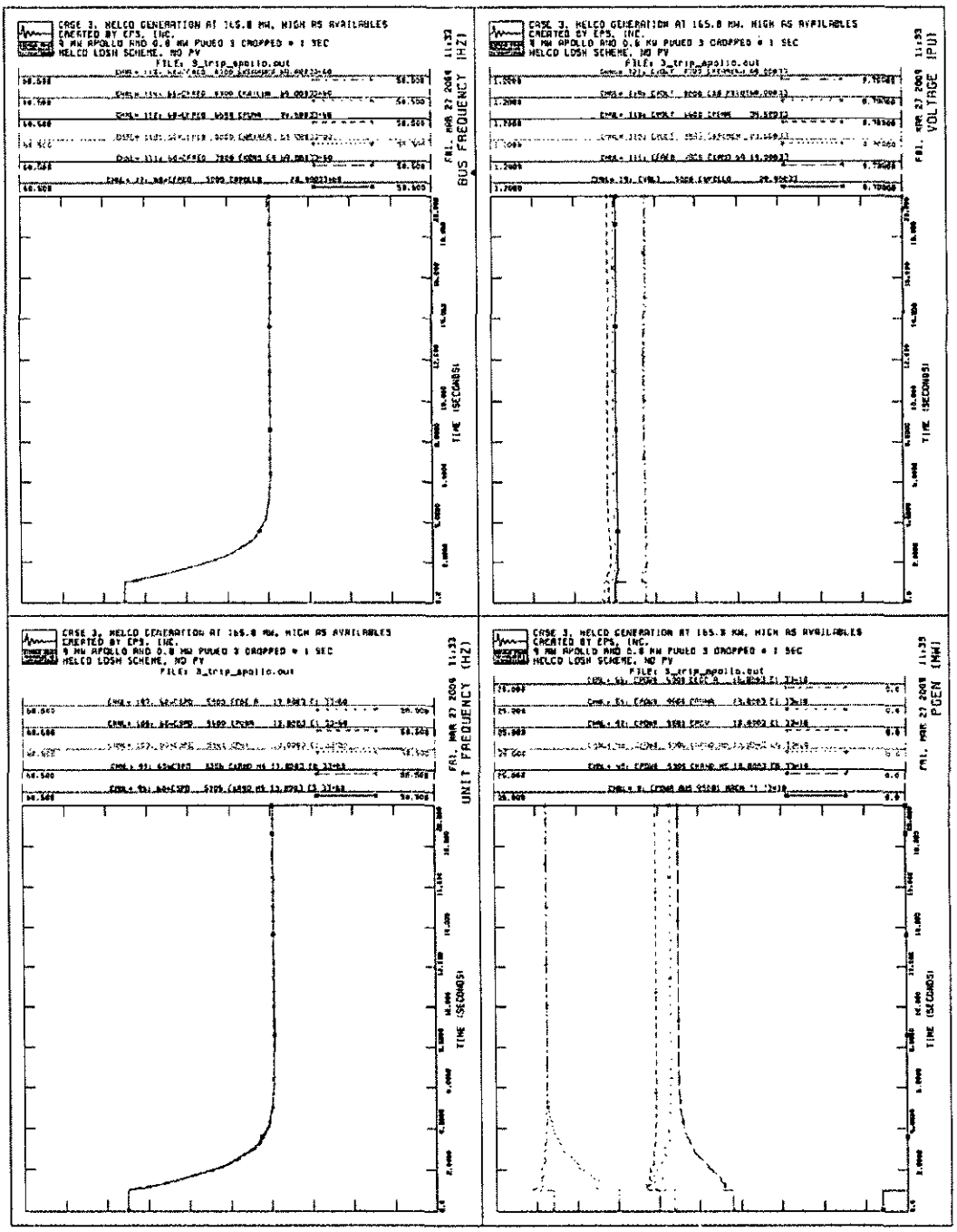
Trip Puna, EPS Load Shed Scheme



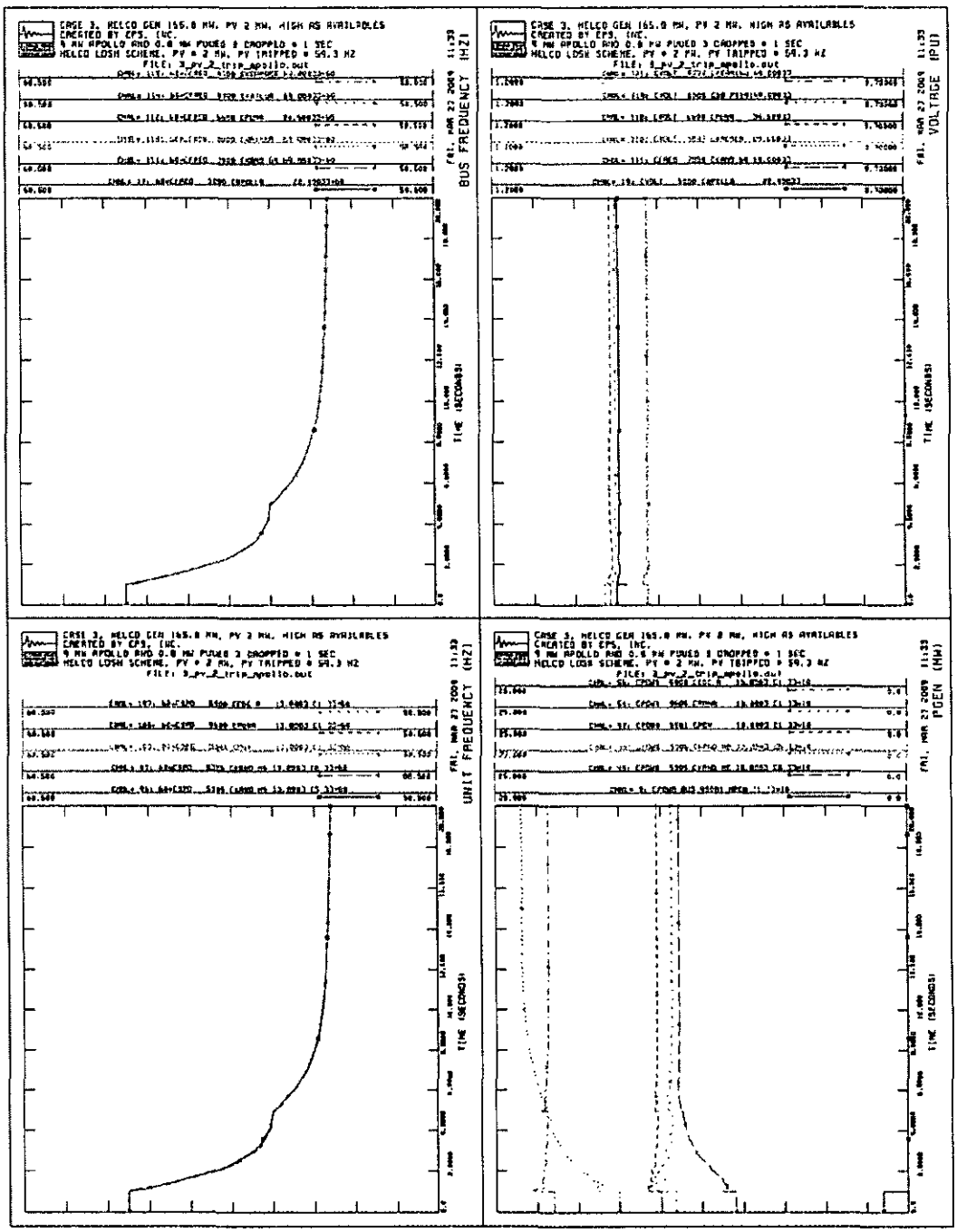
Appendix B – Maximum PV Penetration Stability Plots

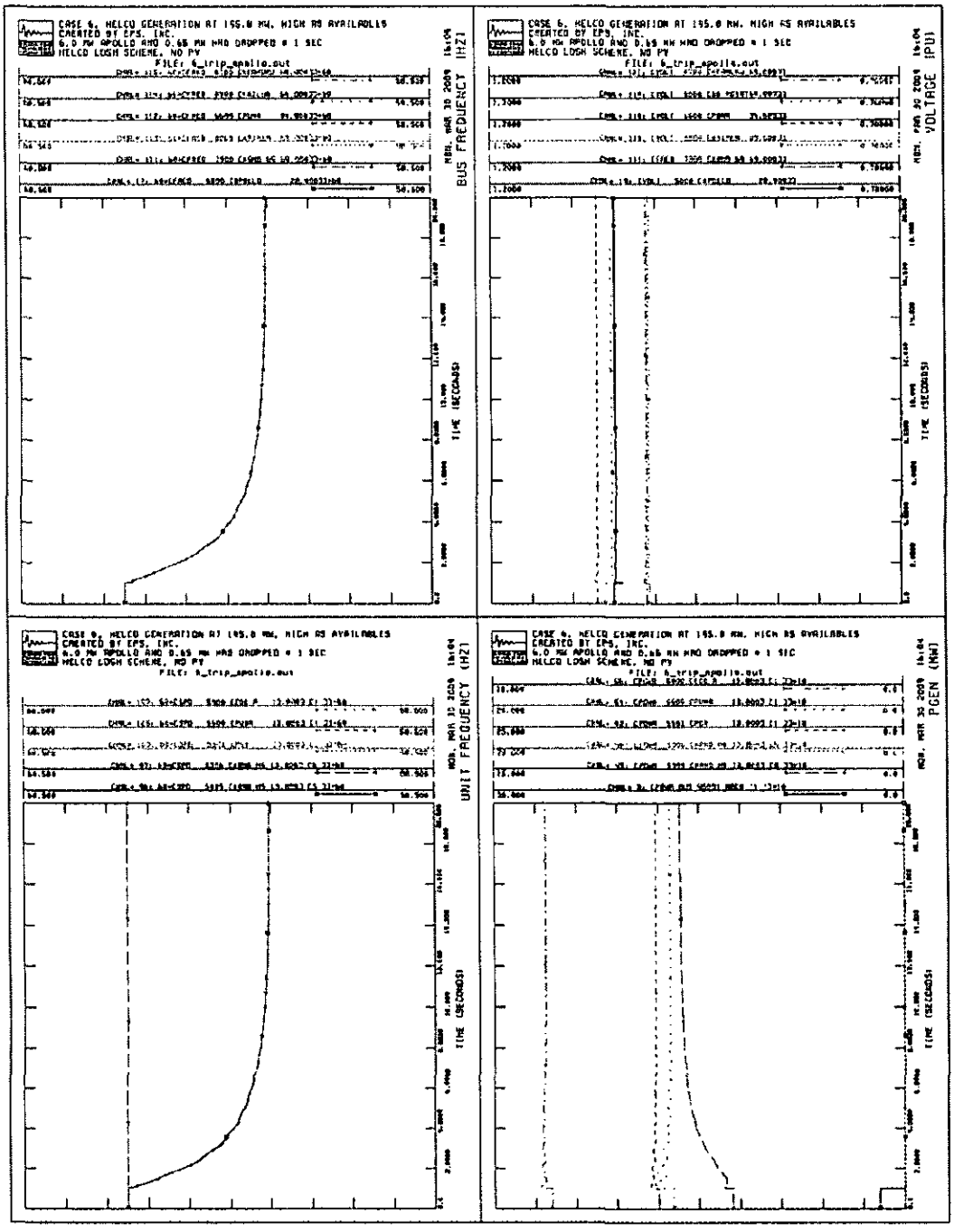

BUS FREQUENCY (HZ)
VOLTAGE (PU)
UNIT FREQUENCY (HZ)
PGEN (MW)
TIME (SECONDS)


BUS FREQUENCY (HZ)
VOLTAGE (PU)
UNIT FREQUENCY (HZ)
PGEN (MW)
TIME (SECONDS)


CASE 3, HELCO GENERATION AT 165.8 MW, HIGH RS AVAILABLES
CREATED BY EPS, INC.
9 MW APOLLO AND 0.8 MW PUUEO 3 DROPPED @ 1 SEC
HELCO LOSH SCHEME, NO PV
FILE: 3_trip_apollo.out
BUS FREQUENCY (HZ)
VOLTAGE (PU)
UNIT FREQUENCY (HZ)
PGEN (MW)
TIME (SECONDS)
FRI, MAR 27 2009 11:33

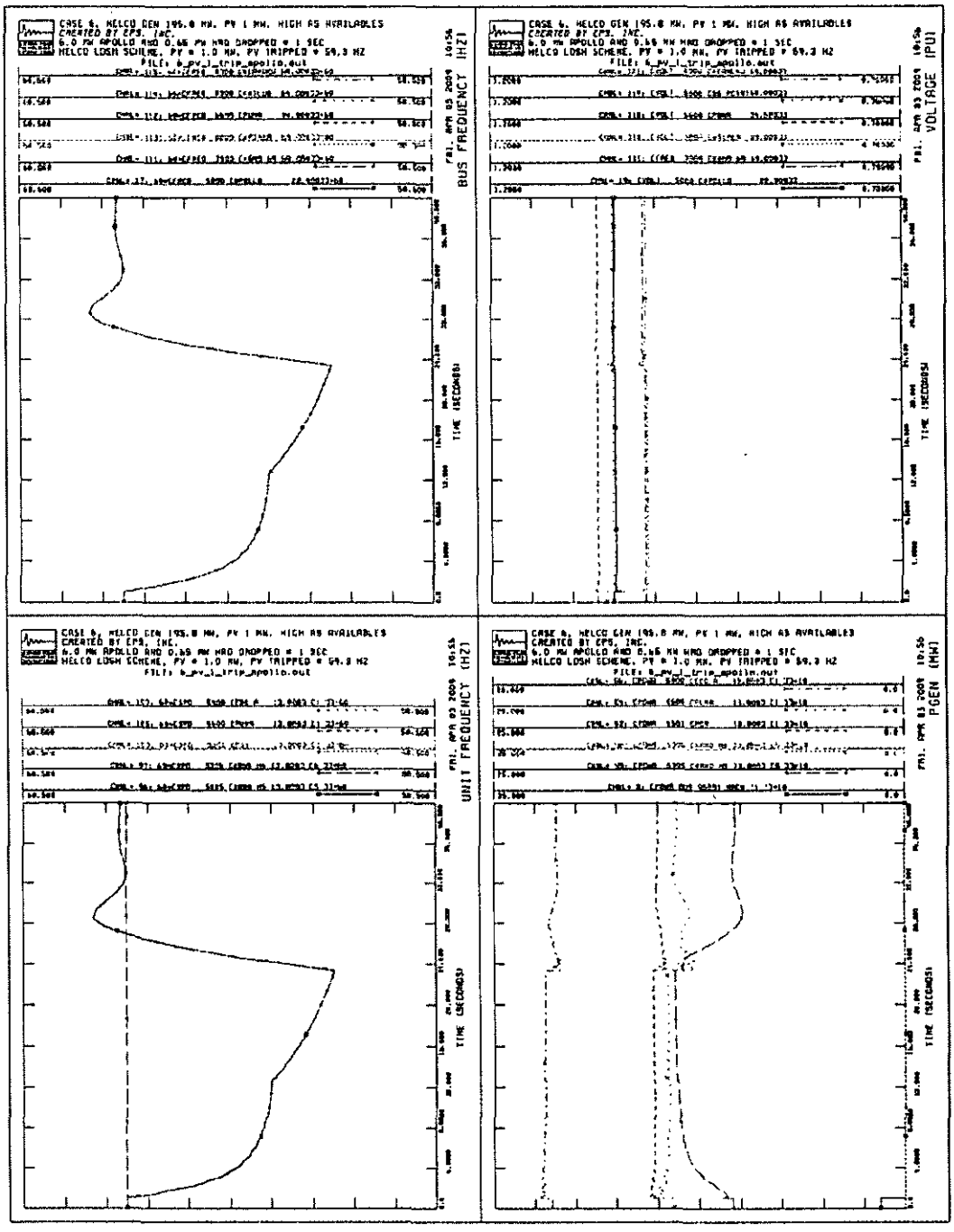
Hawaii Electric Light Company
Maximum Penetration of Distributed Generation Study





Electric Power Systems Inc. Consulting Engineers

Hawaii Electric Light Company
Maximum Penetration of Distributed Generation Study



Electric Power Systems Inc.
Consulting Engineers

LOL-IR-14

Ref: HECO T-1, Page 8, Lines 16 through 20.

"The Companies are in the process of finalizing a request for proposals ("RFP") for consulting services to complete a Smart Grid roadmap and through the RFP process, will select a firm to develop individualized roadmaps charting a Smart Grid course for each of the Companies." (HECO T-1, 8:16-20)

(a) When will HECO roll out its Smart Grid roadmap?
(b) How will individual Smart Grid roadmaps differ?

Hawaiian Electric Companies' Response:

a. See the Hawaiian Electric Companies response to HSEA-HREA-IR-22.

b. Individual Smart Grid roadmaps will address the specific needs of each Hawaiian Electric Company. The roadmap is not completed; therefore, the manner in which the roadmap will differ among the various Hawaiian Electric Companies is not yet available.

LOL-IR-15

Ref: HECO T-1, Page 8, Line 24.

"the technology has rapidly evolved" (HECO T-1, 8:24)

In a period of rapid change, shouldn't one wait to see who the winners and losers are before jumping into the fray?

Hawaiian Electric Companies' Response:

With the developments that have taken place in the AMI marketplace in the past several years and in light of major technology selections made by other utilities, it is possible that a different conclusion could be reached if the implementation were delayed. There are pros and cons of waiting. If the project is delayed, the quantified and potential benefits are delayed. However, more information will be available in the future. A key consideration is how adaptable or useful the proposed system and commercial arrangements will be to support future needs – which are by necessity, or still uncertain at this point in time.

LOL-IR-16

Ref: HECO T-1, Page 9, Lines 2 and 3.

"AMI Networks in particular have moved to the forefront as a key Smart Grid enabling technology" (HECO T-1, 9:2-3)

Where we they before they jumped to the forefront?

Hawaiian Electric Companies' Response:

AMI systems were originally focused on metering and were slowly investigating demand response applications. The federal American Recovery and Reinvestment Act funding for Smart Grid then caused a rapid change in the pace of technology development and utilities and AMI vendors identified the potential for AMI networks to address metering, demand response, and distribution automation (i.e. Smart Grid functionality), including the use of multi-tiered communications networks to responds to low latency Smart Grid requirements.

LOL-IR-17

Ref: HECO T-1, Page 9, Lines 4 and 5.

"vendors have responded enthusiastically by a near explosive expansion of product offerings" (HECO T-1, 9:4-5)

In a period of rapid change, shouldn't one wait to see who the winners and losers are before jumping into the fray?

Hawaiian Electric Companies' Response:

Please see the Hawaiian Electric Companies' response to LOL-IR-15.

LOL-IR-18

Ref: HECO T-1, Page 9, Lines 19 and 20.

"Ultimately, an AMI system will also help to increase the utilization of renewable energy resources." (HECO T-1, 9:19-20)

How long until ultimately occurs?

Hawaiian Electric Companies' Response:

The timeline for AMI to help to increase the utilization of renewable energy resources is not yet defined. Once the Smart Grid Roadmap is complete, more information will be available to aid in defining this timing. The response to HSEA-HREA-IR-22 provides further information pertaining to the Smart Grid Roadmap.

LOL-IR-19

Ref: HECO T-1, Page 9, Lines 21 through 25.

"The Consumer Advocate, the Hawaii Renewable Energy Alliance, the Hawaii Solar Energy Association and Life of the Land, as well as the Commission's consultant, the National Regulatory Research Institute, have provided valuable insight and views on many aspects of the Companies' proposed AMI Project, including the selection of an optimal AMI system." (HECO T-1, 9:21-25)

What specific parts of HECO's proposal come from the insight provided by
(a) The Consumer Advocate?
(b) Hawaii Renewable Energy Alliance?
(c) Hawaii Solar Energy Association?
(d) Life of the Land? and
(e) the National Regulatory Research Institute?

Hawaiian Electric Companies' Response:

a. No parts of Hawaiian Electric Companies' proposal originated from the insight provided by the Consumer Advocate since their input was provided after the instant application was filed with the Commission.

b. No parts of Hawaiian Electric Companies' proposal originated from the insight provided by the Hawaii Renewable Energy Alliance since their input was provided after the instant application was filed with the Commission.

c. No parts of Hawaiian Electric Companies' proposal originated from the insight provided by the Hawaii Solar Energy Association since their input was provided after the instant application was filed with the Commission.

d. No parts of Hawaiian Electric Companies' proposal originated from the insight provided by Life of the Land since their input was provided after the instant application was filed with the Commission.

e. No parts of Hawaiian Electric Companies' proposal originated from the insight provided by the National Regulatory Research Institute since their input was provided after the instant application was filed with the Commission.

LOL-IR-20

Ref: HECO T-1, Page 10, Lines 5 through 7.

"Approval of the proposed AMI Project will create an opportunity to move forward on clean energy objectives by bringing "smart" capabilities and programs to life" (HECO T-1, 10:5-7)

Does that mean that in the past un-smart and/or dumb capabilities and programs
(a) existed?
(b) were promoted?
(c) came to life?

Hawaiian Electric Companies' Response:

a. The proposed AMI project will provide data from hundred of thousands of meters and enable the installation of thousands of other sensors on the grid, utilizing a common communications network. To varying degrees, the grid can be considered dumb in that there are a limited number of sensors on the grid and most meters are indeed "dumb".

b. See the Hawaiian Electric Companies' response to part a.

c. See the Hawaiian Electric Companies' response to part a.

LOL-IR-21

Ref: HECO T-100, Page 2.

Did the witness also offer formal testimony in a public hearing held by the Board of Land and Natural Resources?

Hawaiian Electric Companies' Response:

This question is beyond the scope of the instant application.

LOL-IR-22

Ref: HECO T-2, Page 2, Lines 21 and 22.

"AMI meters and components of the AMI Network will be installed on the islands of Oahu, Maui and Hawaii." (HECO T-2, 2:21-22)

Does it seem fair that Lanai and Molokai residents each get 200MW of wind for O`ahu customers, but then do not get the benefit of AMI?

Hawaiian Electric Companies' Response:

Please see HECO T-2 (pages 12-13).

LOL-IR-23

Ref: HECO T-2, Page 3, Lines 16 through 18.

"These schedules are planning estimates and will need to be adjusted if steps required to move forward such as Commission approval and MDMS development require more time." (HECO T-2, 3:16-18)

Do you plan on delaying this docket or was this docket prematurely opened?

Hawaiian Electric Companies' Response:

In HECO T-2 (page 3, lines 16-18), the Hawaiian Electric Companies clarified the basis of the proposed project deployment schedule. There have been a number of many developments since the submittal of the instant Application, such as rapid technology evolution (as described on pages 15 through 23 of HECO T-2) and new Smart Grid requirements, which may result from the Smart Grid Roadmap (as described in the Hawaiian Electric Companies response to HSEA-HREA-IR-22), which should be reviewed and considered to ensure that the implemented AMI system fully meets the current and foreseeable requirements and capabilities. See response to LOL-IR-15.

LOL-IR-24

Ref: HECO T-2, Page 4, Lines 2 and 3.

"All of the advanced meters will have the capability to capture interval meter reads at configurable intervals (such as 15-minute or one-hour)" (HECO T-2, 4:2-3)

(a) What is the minimum time interval that could occur utilizing this system?
(b) Why not take readings every 5 seconds?

Hawaiian Electric Companies' Response:

a. Please refer to the response to PUC-IR-21.

b. Capturing data at five second intervals with an AMI system would not be economical.

Please refer to the response to PUC-IR-21.

LOL-IR-25

Ref: HECO T-2, Page 4, Lines 19 through 21.

"The Companies would install utility-owned Sensus iConA residential meters and Elster C&I meters equipped with Sensus FlexNet radio boards." (HECO T-2, 4:19-21)

(a) Why or why wasn't competitive bidding used in this proposal?
(b) Would Competitive Bidding have resulted in a lower price?

Hawaiian Electric Companies' Response:

a. See part b to the Hawaiian Electric Companies' response to CA-IR-34.

b. A stated within part a to the Hawaiian Electric Companies response to CA-IR-34, at the time of the selection, Sensus Metering Systems was the only AMI vendor which met the Hawaiian Electric Companies' requirements of a non-mesh fixed radio frequency technology. As such, performing a formal competitive bidding process would have resulted in increased AMI project costs (related to performing the competitive bidding process) with no expected reduction in price.

LOL-IR-26

Ref: HECO T-2, Page 6, Lines 7 through 9.

"The Smart Grid promises unparalleled capabilities in monitoring, controlling, optimizing and automating the restoration of the electric power delivery system." (HECO T-2, 6:7-9)

(a) Does that imply that those controlling the system will have unparalleled opportunities to monitor and control those receiving power?

(b) Wouldn't another approach, perhaps more Republican in nature, focus on allowing individuals and companies to decrease their energy use without having Big Brother having access to all sorts of private information?

Hawaiian Electric Companies' Response:

a. No. Customers who elect to allow the utility to control any of their end-uses would participate in such programs under specific circumstances and they will typically have the ability to override utility control (i.e., Hawaiian Electric's Energy Scout water heater load control program).

b. The Hawaiian Electric Companies have strict business rules and there is no Big Brother concept.

LOL-IR-27

Ref: HECO T-2, Page 6, Lines 9 through 11.

"Collectively, AMI and DR offer important alternatives, in addition to renewable energy, to help address global energy supply and environmental issues." (HECO T-2, 6:9-11)

(a) Does AMI and DR reduce the average cost of electricity by making its use more efficient?
(b) If the cost of business drops, then, utilizing a simply supply-demand curve, wouldn't output (number of units) increase?
(c) Which is greater: the drop in average use of electricity, or the increased electrical use from increasing output?

Hawaiian Electric Companies' Response:

a. AMI and Demand Response ("DR") can contribute to more efficient grid operations by managing peak loads and providing data to optimize and balance feeder and transformer loading to reduce system losses.

b. No. If the cost of business drops for the Hawaiian Electric Companies, these cost savings are passed on to the customer in terms of reduced revenue requirements in the next rate case.

c. Question is not clear. AMI and DR are intended to support a reduction in the amount of electricity used as well as reducing use during peak demand periods.

LOL-IR-28

Ref: HECO T-2, Page 6, Lines 12 and 13.

"In short, the implementation of AMI is being driven by significant developments in the evolution and availability of AMI-related technologies" (HECO T-2, 6: 12-13)

Will AMI be driven in large amounts by the changes in technology that are developed in the next few years?

Hawaiian Electric Companies' Response:

a. Yes. AMI technology is evolving rapidly, especially as it relates to communications technology and communication architecture.

LOL-IR-29

Ref: HECO T-2, Page 6, Lines 12 through 14.

"In short, the implementation of AMI is being driven by ... AMI'S increasing popularity on the U.S. mainland" (HECO T-2, 6:12-14)

(a) Should we decide how popular an issue is on the Mainland to determine whether we should do it here?
(b) How much weight should we give to Mainland popularity?
(c) Should Mainland popularity help determine whether we implement in Hawaii various things such as wheeling, Independent System Operators (ISOs) and AMI?
(d) Doesn't HECO constantly say we are not the Mainland, we are different?
(e) Has your position changed in this regard?
(f) Are you arguing both sides of this issue?

Hawaiian Electric Companies' Response:

a. No. However, the market for AMI technology on the mainland has driven the price and features of AMI products downwards, making it cost effective.

b. Implementation activity on the mainland is diverse and provides advance insight into AMI technology implementation with different products and technologies – both hardware and software. This is useful to the Hawaiian Electric Companies in advance of the proposed AMI deployment. A good example is the reliability of meters and network performance experiences of AMI systems by mainland utilities.

c. See the response to part a. and b.

d. The Hawaiian Electric Companies each operate in a unique environment. See the response to part a. and b.

e. No.

f. No.

LOL-IR-30

Ref: HECO T-2, Page 6, Lines 12 through 15.

"In short, the implementation of AMI is being driven by ... uncertainty in the future price of fuel." (HECO T-2, 6:12-15)

(a) When did the price of fuel become volatile?
(b) Didn't HEI make this same argument in "Alterative Energy Development" filed with the State Legislature in 1994?

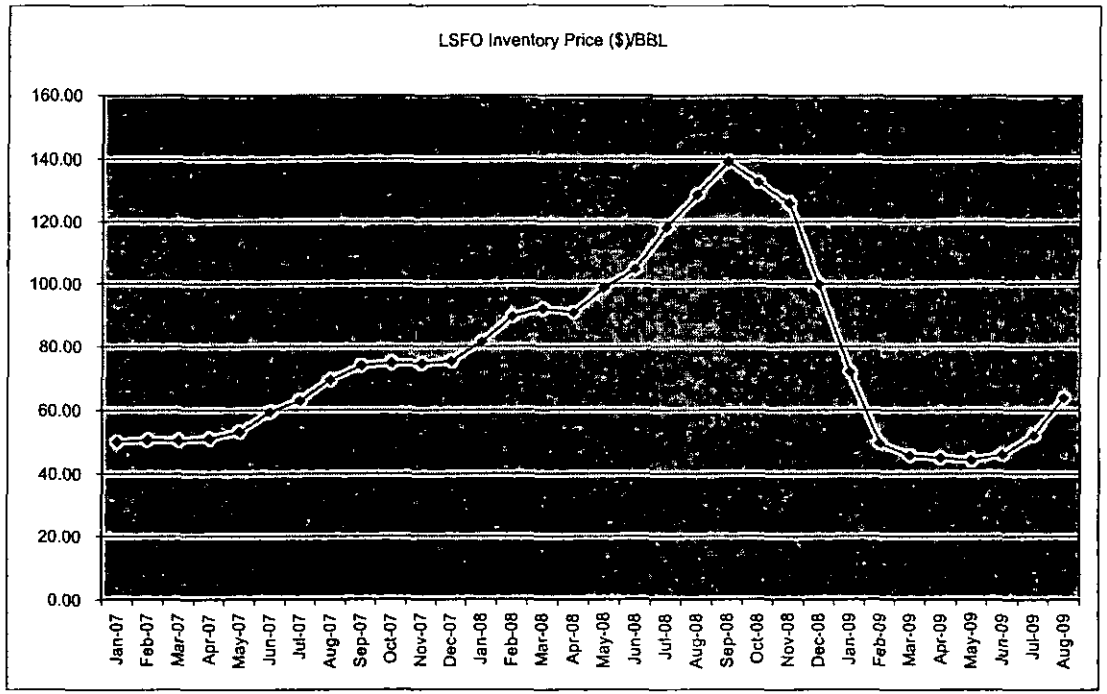
Hawaiian Electric Companies' Response:

a. The uncertainty in the future price of fuel is illustrated by Low Sulfur Fuel Oil (LSFO) inventory prices which ranged from $50 to $139 per barrel over a two year period (see Attachment 1 to this response). As stated in HECO ST-10B (Docket 2008-0083), fuel prices constitute a large and volatile cost for utilities and this has a direct impact on electricity prices.

b. The Hawaiian Electric Companies have been working in the alternative energy field for many years, including 1994. Mr. Fetherland is not aware of any arguments made by HEI in "Alterative Energy Development" filed with the State Legislature in 1994.

Hawaiian Electric Company, Inc.

(1) Effective Date	(3) LSFO Inventory Price ($) / BBL
01-01-07	50.05
02-01-07	50.65
03-01-07	50.34
04-01-07	51.02
05-01-07	53.06
06-01-07	59.38
07-01-07	62.87
08-01-07	69.35
09-01-07	73.92
10-01-07	74.65
11-01-07	74.50
12-01-07	75.28
01-01-08	81.48
02-01-08	89.60
03-01-08	91.99
04-01-08	90.89
05-01-08	98.66
06-01-08	104.63
07-01-08	118.16
08-01-08	128.74
09-01-08	139.17
10-01-08	132.79
11-01-08	125.89
12-01-08	99.81
01-01-09	72.09
02-01-09	49.65
03-01-09	45.66
04-01-09	44.93
05-01-09	44.21
06-01-09	45.84
07-01-09	51.89
08-01-09	63.91



LOL-IR-30
DOCKET NO. 2008-0303
ATTACHMENT 1
PAGE 1 OF 1

LOL-IR-31

Ref: HECO T-2, Page 6, Lines 15 and 16.

"AMI has - particularly in recent years - received wide support at both state and federal levels." (HECO T-2, 6:15-16)

What kinds of opposition to AMI and Smart Grids has arisen in the past few years?

Hawaiian Electric Companies' Response:

The statement indicates positive support for AMI and Smart Grid.

LOL-IR-32

Ref: HECO T-2, Page 6, Lines 21 and 22.

"The Companies' specific objectives with respect to the AMI project are: ... (2) provide 15-minute or one-hour interval data to customers" (HECO T-2, 6:21-22)

Why was this information labeled CBI (subject to Protective Order) in HECO's initial application?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies specific objective with respect to the AMI project were not provided under Protective Order. If Life of the Land is referring to Exhibit 10 of the Application (which itemizes the features of the Sensus AMI meters including interval settings available and provides technical details for these meters), it was originally provided under protective order to honor the terms under which Sensus provided this information.

LOL-IR-33

Ref: HECO T-2, Page 6, Footnote 2.

"The advanced meters selected by the Hawaiian Electric Companies can be configured to provide as low as 5-minute interval data." (HECO T-2, 6: footnote 2)

How much added cost would be needed to reconfigure the Ami to get readings in shorter time intervals?

Hawaiian Electric Companies' Response:

The AMI meters are designed to provide interval data as low as 5-minutes. Configuring these meters to obtain readings in a shorter time interval is not possible with the current meter designs. In addition, the balance of the AMI system is not designed to handle the data volumes that would result from setting intervals below 15-minutes. See the Hawaiian Electric Companies' response to PUC-IR-21 for additional information.

LOL-IR-34

Ref: HECO T-2, Page 8, Lines 13 and 14.

"The Companies proposed the AMI project as a first step in a broader Smart Grid initiative" (HECO T-2, 8:13-14)

Will any part of AMI be installed on
(a) County property?
(b) State property?
(c) Federal Property?

Hawaiian Electric Companies' Response:

a. Yes. The new AMI meters will replace the existing meters on County property. No other AMI equipment is expected to be installed on County property.

b. Yes. The new AMI meters will replace the existing meters on State property. No other AMI equipment is expected to be installed on State property.

c. Yes. The new AMI meters will replace the existing meters on Federal property. No other AMI equipment is expected to be installed on Federal property.

LOL-IR-35

Ref: HECO T-2, Page 17, Lines 14 through 16.

"A credible argument can be made that there is a constant evolution in AMI technologies and that waiting for the ultimate solution will cause a delay in obtaining significant customer benefits." (HECO T-2, 17: 14-16)

(a) In conducting due diligence to evaluate the relative values of diving right in or holding off for a year or two during this period of enormous changes in AMI and Smart Grid technologies and products, what specific criteria did HECO use?
(b) What value or weight did HECO give to each criterion?
(c) Why?

HECO Companies' Response:

a. As stated within part a of the Hawaiian Electric Companies response to CA-IR-34, at the time of the selection, Sensus Metering Systems was the only AMI vendor which met the Hawaiian Electric Companies requirements of a non-mesh, fixed radio frequency technology. The Hawaiian Electric Companies' goal was to execute an agreement with the AMI vendor in order to mitigate potential cost overruns given that the meter and network costs constitute 73% of the total AMI project costs (as shown on Table 3, of Attachment 1, to the Hawaiian Electric Companies response to CA-IR-35).

b. The Hawaiian Electric Companies focused on non-mesh, fixed radio frequency AMI technology. Pilot project work was performed in order to examine functions and features available with the Sensus AMI technology prior to execution of the Sensus Agreement in October 2008.

c. Weighting criteria was not used in the original selection of the Sensus technology since, as stated within part a of the Hawaiian Electric Companies response to CA-IR-34, at the time of the selection, Sensus Metering Systems was the only AMI vendor which met the

Hawaiian Electric Companies requirements for a non-mesh fixed radio frequency technology.

LOL-IR-36

Ref: HECO T-2, Page 20, Lines 3 through 9.

"The Consumer Advocate contends that the Hawaiian Electric Companies' decision to abstain from using a bidding process does not cast a favorable light on the determination that the project costs are reasonable. The Hawaiian Electric Companies have provided substantial technical details and an AMI financial model which includes all the assumptions and cost estimates employed by the Hawaiian Electric Companies as well as the entire Sensus Agreement for review by the parties to this docket." (HECO T-2, 20:3-9)

Hawaiian Electric Companies' Response:

This is acknowledged by the Hawaiian Electric Companies.

LOL-IR-37

Ref: HECO T-3, Page 1, Lines 16 through 19.

"The Companies' cost estimates were developed by gathering and evaluating information from vendors, consultants, pending contracts and historical experience." (HECO T-3, 1:16-19)

(a) What specific historical sources did you research?

Hawaiian Electric Companies' Response:

a. The sources of information for the cost estimates are defined in the AMI financial model ("AMI Model") which was submitted as Attachment 1 to the response to PUC-IR-23. The AMI Model Narrative, submitted as Attachment 2 to the response to CA-IR-2 explains the calculations and assumptions with the AMI Model. Examples of the Hawaiian Electric Companies' historical experience sources include: customer counts, sales information, growth rates (customers, sales, net energy metering), on-costs, overheads, contractor rates, meter population, MV90 meter population, meter installation labor requirements, computer hardware and software costs, interfacing and operation of legacy systems (e.g., Customer Information System, IVR, Vignette, etc.), meter reading costs and head counts, field service costs and head counts, system losses, etc.

LOL-IR-38

Ref: HECO T-7, Page 2, Lines 3 through 7.

"TOU rate options are available for all Hawaiian Electric customers, as approved in Hawaiian Electric's 2005 test year rate case (Docket No. 04-0113). Similar TOU options are proposed in the currently open HELCO 2006 test year rate case (Docket No. 05-0315) and MECO 2007 test year rate case (Docket No. 2006-0387)." (HECO T-7, 2:3-7)

Can you please spell out the specifics for each utility?

Hawaiian Electric Companies' Response:

Please see the attached tariff sheets for time-of-use ("TOU") rate options:

Attachment 1 - HECO, Docket No. 04-0113 approved rates;

Attachment 2 - HELCO, Docket No. 05-0315 proposed rates; and

Attachment 3 - MECO, Docket No. 2006-0387 proposed rates.

Superseding Revised Sheet No. 61
Effective January 1, 1995

REVISED SHEET NO. 61
Effective June 20, 2008

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads equal to or greater than 300 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders M, T, and I.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period.	7:00 a.m. - 9:00 p.m., Daily
Priority Peak.	5:00 p.m. - 9:00 p.m., Monday through Friday
Mid-Peak.	All On-Peak hours outside of Priority Peak hours
Off-Peak.	9:00 p.m. - 7:00 a.m., Daily

RATE:

CUSTOMER CHARGE - per month	$350.00/month
DEMAND CHARGE - (To be added to Customer Charge)	
Priority Peak - per kW of billing demand	$18.00/kW
Mid-Peak - per kW of billing demand	$16.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the Priority Peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE - (To be added to Customer and Demand Charges)

All On-Peak kWhr per month	- per kWhr	13.7277 ¢/kWhr
All Off-Peak kWhr per month	- per kWhr	10.0000 ¢/kWhr

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 61A
Effective January 1, 1995

REVISED SHEET NO. 61A
Effective June 20, 2008

SCHEDULE U - (continued)

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge calculation for each month shall be the highest of the maximum on-peak demands for such month but not less than 300 kW.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month but not less than 300 kilowatts.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation - 3.0%
Distribution voltage supplied without further transformation - 2.1%

Superseding Revised Sheet No. 61B
Effective January 1, 1996

REVISED SHEET NO. 61B
Effective June 20, 2008

SCHEDULE U -(continued)

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.6%, respectively.

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system the Company will deliver and meter service to customers in this area at 120/208Y or 277/480Y volts (See Rule 2). The demand and energy charges will be increased 0.9%.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, Power Factor adjustment, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

TERM OF CONTRACT:

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charge the total connection costs incurred by the Company to serve the customer less any customer advance and/or contribution paid by the customer.

Superseding Revised Sheet No. 67
Effective June 13, 2008

REVISED SHEET NO. 67
Effective June 20, 2008

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers on rate Schedule J, PS, PP, or PT but cannot be used in conjunction with the load management Rider M, Rider I, Schedule U, and Schedule TOU-C. A customer may utilize this Rider in conjunction with Schedule SS.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., Daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., Daily

RATE:

The rate(s) for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate Schedule J, PS, PP, or PT except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month $10.00

TIME-OF-DAY ENERGY CHARGE ADJUSTMENTS:

On-Peak Energy Surcharge - all on-peak kwh +2.00 cents/kwh
Off-Peak Energy Credit - all off-peak kwh -3.00 cents/kwh

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge. In addition, the monthly average energy charge computed from the regular energy charge and the above Time-of-Day energy charge adjustments including the energy cost adjustment, cannot be lower than the off-peak avoided energy cost at the metering point.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak Kw demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 67A
Effective January 1, 1995

REVISED SHEET NO. 67A
Effective June 20, 2008

Rider T (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

MEASUREMENT OF TIME-OF-DAY ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and maximum kW demand during the time-of-day rating periods.

TERMS OF AGREEMENT:

A customer applying for service under this Rider shall sign a standard Rider T contract form with the Company. Service under this Rider shall not be less than five years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of discount received under this Rider.

A customer may perform emergency maintenance on his equipment or load served under this rider during the on-peak period and the customer's maximum demand during that time will not be considered in the determination of the billing kW demand under the following conditions:

a. The conditions under which the customer may perform emergency maintenance on his equipment or load during on-peak period will be defined in the customer's contract.

b. The customer may perform such emergency maintenance during on-peak period only when approved by HECO, and will operate only for the duration approved by HECO. Such HECO approval shall be by phone, or by e-mail, or in writing to the customer.

c. The customer must notify HECO as far in advance as possible, but not less than 1 hour before performing such emergency maintenance on his equipment or load during the on-peak period. Such notice shall be by phone, by e-mail, or in writing. HECO may approve the customer's request on capacity availability

Rider T - (continued)

basis. Service to the customer under this condition may be interrupted at any time when HECO's system conditions dictate the necessity to interrupt service, or when in HECO's sole judgment the system may be impaired or the startup of another unit would be uneconomic.

d. The customer's request to operate its load during the on-peak period under this condition cannot exceed four (4) times within a 12-month period.

SHEET NO. 83
Effective June 20, 2008

SCHEDULE TOU-C

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than 300 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders M, T, and I.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

Priority Peak:	5:00 p.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

RATE:

NON-DEMAND SERVICE:
Applicable to general light and/or power loads less than or equal to 5000 kWhr per month, and less than 25 kW, and supplied and metered at single voltage and delivery point.

CUSTOMER CHARGE:	
Single-Phase Service - per month	$30.00/month
Three-Phase Service - per month	$55.00/month
ENERGY CHARGE: (To be added to Customer Charge)	
Priority Peak Period - per kWhr	21.4205 ¢/kWhr
Mid-Peak Period - per kWhr	18.4205 ¢/kWhr
Off-Peak Period - per kWhr	11.4205 ¢/kWhr
MINIMUM CHARGE:	
Single-Phase Service - per month	$30.00/month
Three-Phase Service - per month	$55.00/month

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
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SHEET NO. 84
Effective June 20, 2008

SCHEDULE TOU-C - continued

DEMAND SERVICE:

Applicable to general light and/or power loads greater than 5000 kWhr per month, or equal to or greater than 25 kW but less than 300 kW, and supplied and metered at single voltage and delivery point.

CUSTOMER CHARGE:

Single-Phase Service - per month	$50.00/month
Three-Phase Service - per month	$70.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	18.0460 ¢/kWhr
Mid-Peak Period - per kWhr	15.0460 ¢/kWhr
Off-Peak Period - per kWhr	10.0000 ¢/kWhr

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak - per kW of billing demand	$15.00/kW
Mid-Peak - per kW of billing demand	$8.50/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

HAWAIIAN ELECTRIC COMPANY, INC.

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SHEET NO. 85
Effective June 20, 2008

SCHEDULE TOU-C - (continued)

Power Factor: (Applicable to Demand Service)

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery: (Applicable To Demand Service)

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation -3.0%
Distribution voltage supplied without further transformation -2.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 2.4% and 0.6%, respectively.

Because of the inherent operating conditions in the downtown area supplied from the Company's underground network system the Company will deliver and meter service to customers in this area at 120/208Y or 277/480Y volts (See Rule 2). The demand and energy charges will be increased 0.9%.

Energy Cost Adjustment Clause: (For Non-Demand and Demand Service)

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, and Power Factor adjustment.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

SHEET NO. 85A
Effective June 20, 2008

SCHEDULE TOU-C - (continued)

Integrated Resource Planning Surcharge: (For Non-Demand and Demand Service)

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Service Voltage adjustment, Network Service adjustment, Power Factor adjustment, and energy cost adjustment.

Rules and Regulations: (For Non-Demand and Demand Service)

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

TERM OF CONTRACT: (For Non-Demand and Demand Service)

Not less than five years beginning from the service start date. If service is terminated before the end of the contract term, the customer shall be charge the total connection costs incurred by the Company to serve the customer less any customer advance and/or contribution paid by the customer.

Superseding Sheet No. 86
Effective May 12, 2003

REVISED SHEET NO. 86
Effective June 20, 2008

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential power service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltage specified by the Company.

This Schedule is limited to 1,000 residential customers on a first come first serve basis until the new Customer Information System is implemented.

RATES:

CUSTOMER CHARGE - $ per customer per month:	
Single-Phase Service - per month	$9.50/month
Three-Phase Service - per month	$17.50/month
TIME-OF-USE ENERGY CHARGE - ¢ per kWh:	
Priority Peak Period - per kWhr	22.1896 ¢/kWhr
Mid-Peak Period - per kWhr	19.1896 ¢/kWhr
Off-Peak Period - per kWhr	13.6896 ¢/kWhr
MINIMUM CHARGE:	
Single-Phase Service - per month	$17.50/month
Three-Phase Service - per month	$22.50/month

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Sheet No. 87
Effective May 12, 2003

REVISED SHEET NO. 87
Effective June 20, 2008

SCHEDULE TOU-R - (continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m., Monday-Friday
Mid-Peak:	7:00 a.m.-5:00 p.m., Monday-Friday
	5:00 p.m.-9:00 p.m., Saturday-Sunday, Holidays
Off-Peak:	7:00 a.m.-5:00 p.m., Saturday-Sunday, Holidays
	9:00 p.m.-7:00 a.m., Daily

Holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1. The Company may meter the customer's energy usage pattern for one to three months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2. The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3. The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Sheet No. 88
Effective May 12, 2003

REVISED SHEET NO. 88
Effective June 20, 2008

Schedule TOU-R - (continued)

TERMS AND CONDITIONS - continued:

4. A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 56
Effective February 15, 2001

REVISED SHEET NO. 56
Effective

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 25 kilowatts and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders "M", "T","I", Schedule TOU-J and Schedule TOU-P. This rate is closed to new customers after ____, 2006.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month	$200.00
DEMAND CHARGE - (To be added to Customer Charge)	
All On-Peak kWh of billing demand - per kW	$28.00
ENERGY CHARGE - (To be added to Customer and Demand Charges)	
All On-Peak kWhr per month - per kWhr	26.4456¢
All Off-Peak kWhr per month - per kWhr	21.1630¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Superseding Sheet No. 56A
Effective February 21, 1995

REVISED SHEET NO. 56A
Effective

Schedule "U" (Continued)

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charges applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge of calculation for each month shall be the highest of the maximum on-peak demand for such month, but not less than 25 kW.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and peak load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month, but not less than 25 kilowatts.

Power Factor:

For customers with on-peak or off-peak demands in excess of 200 kilowatts per month one time within a twelve-month period, the following power factor adjustment shall apply to the above energy and demand charges.

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates will be decreased or increased, respectively, by 0.15%

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Superseding Sheet No. 56B
Effective February 21, 1995

REVISED SHEET NO. 56B
Effective

Schedule "U" (Continued)

Transmission voltage supplied without further transformation 4.0%
Distribution voltage supplied without further transformation 2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

TERM OF CONTRACT:

Not less than five years.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 62
Effective February 21, 1995

REVISED SHEET NO. 62
Effective

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers in rate Schedule "J" or "P" but cannot be used in conjunction with the load management Rider M, Rider I, Schedule U, Sched TOU-J and Sched TOU-P. This rate is closed to new customers after ____, 2006.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATES:

The rates for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate schedule J or P, except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month		$10.00
TIME-OF-DAY ENERGY CHARGE ADJUSTMENT:		
On-Peak Energy Surcharge	- all on-peak kWhr	+ 2.50¢
Off-Peak Energy Credit	- all off-peak kWhr	- 3.15¢

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak kW demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

Superseding Revised Sheet No. 62A
Effective February 21, 1995

REVISED SHEET NO. 62A
Effective

Rider "T" (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kWhr consumption and maximum kW demand during the time-of-use rating periods.

TERMS OF AGREEMENT:

The customer applying for service under this Rider shall sign a standard Rider T contract form with the Company. Service under this Rider shall not be less than five (5) years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of savings received under this Rider.

SHEET NO. 71
Effective

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

Service under this Schedule shall be limited to a total of 300 meters.

RATES:

CUSTOMER CHARGE - $ per customer per month:	
Single-Phase Service - per month	$11.00/month
Three-Phase Service - per month	$15.50/month

ENERGY CHARGES - ¢ per kWh:

Base Charges	
First 300 kWh per month - per kWhr	29.5470 ¢/kWhr
Next 700 kWh per month - per kWhr	31.6575 ¢/kWhr
All kWh over 1,000 kWh per month-per kWhr	32.5316 ¢/kWhr
Time-of-Use Charges	
Priority Peak Period - per kWhr	5.0 ¢/kWhr
Mid-Peak Period - per kWhr	2.5 ¢/kWhr
Off-Peak Period - per kWhr	- 5.0 ¢/kWhr

SHEET NO. 71A
Effective

SCHEDULE TOU-R - (continued)

MINIMUM CHARGE:

The minimum charge shall be the higher of $20.00 or the bill calculated at base rates plus current rate adjustments using 15% of the customer's highest billed kWh over the previous 11 billing months.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m., Monday-Friday
Mid-Peak:	7:00 a.m.-5:00 p.m., Monday-Friday 7:00 a.m.-9:00 p.m., Saturday-Sunday
Off-Peak:	9:00 p.m.-7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

SHEET NO. 71B
Effective

Schedule TOU-R - (continued)

TERMS AND CONDITIONS - continued:

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 72
Effective

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

Service under this Schedule shall be limited to a total of 100 meters.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	$39.00/month
Three-Phase Service - per month	$61.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	37.5821 ¢/kWhr
Mid-Peak Period - per kWhr	35.0821 ¢/kWhr
Off-Peak Period - per kWhr	27.5821 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SHEET NO. 72A
Effective

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

SHEET NO. 72B
Effective

SCHEDULE TOU-G - continued

TERMS AND CONDITIONS - continued:

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 73
Effective

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 300 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule U, and Schedule TOU-P.

Service under this Schedule shall be limited to a total of 50 meters.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	$49.00/month
Three-Phase Service - per month	$75.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak - per kW of billing demand	$19.25/kW
Mid-Peak - per kW of billing demand	$12.00/kW.

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period - per kWhr	32.4980 ¢/kWhr
Mid-Peak Period - per kWhr	30.4980 ¢/kWhr

SHEET NO. 73A
Effective

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%

HAWAII ELECTRIC LIGHT COMPANY, INC.

Docket No. 05-0315, D&O No. _____.

SHEET NO. 73B
Effective

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation -4.0%
Distribution voltage supplied without further transformation -2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 74
Effective

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule TOU-P.

Service under this Schedule shall be limited to a total of 12 eters.

RATE:

CUSTOMER CHARGE:	$510.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$24.50/kW
Mid-Peak	- per kW of billing demand	$19.50/kW.

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	29.7646 ¢/kWhr
Mid-Peak Period	- per kWhr	27.7646 ¢/kWhr
Off-Peak Period	- per kWhr	17.7646 ¢/kWhr

SHEET NO. 74A
Effective

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 200 kW

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 200 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%

SHEET NO. 74B
Effective

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation -4.0%
Distribution voltage supplied without further transformation -2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 62
Effective May 5, 1997

REVISED SHEET NO. 62
Effective

MAUI DIVISION

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers on rate Schedule "J", "K", or "P" but cannot be used in conjunction with the load management Rider M, Schedules "U", "TOU-J" or "TOU-P".

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., Daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., Daily

RATE:

The rate(s) for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate schedule, except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month		$10.00
TIME-OF-DAY ENERGY CHARGE ADJUSTMENTS:		
On-Peak Energy Surcharge	- all on-peak kwh	+ 2.0 cents/kwh
Off-Peak Energy Credit	- all off-peak kwh	- 3.0 cents/kwh

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge. In addition, the average energy charge computed from the regular energy charge and the above Time-of-Day energy charge adjustments including the energy cost adjustment, cannot be lower than the off-peak avoided energy cost at the metering point.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak Kw demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

Superseding Revised Sheet No. 62A
Effective August 18,1994

REVISED SHEET NO. 62A
Effective

MAUI DIVISION

Rider T (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

MEASUREMENT OF TIME-OF-DAY ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and peak kW demand during the time-of-day rating periods.

TERMS OF AGREEMENT:

The customer applying for service under this Rider shall sign a standard Rider T agreement form with the Company. Service under this Rider shall not be less than five years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of discount received under this Rider.

A customer may perform emergency maintenance on his equipment or load served under this rider during the on-peak period and the customer's maximum demand during that time will not be considered in the determination of the billing kw demand under the following conditions:

a. The conditions under which the customer may perform emergency maintenance on his equipment or load during on-peak period will be defined in the customer's contract.

b. The customer may perform such emergency maintenance during on-peak period only when approved by MECO, and will operate only for the duration approved by MECO. Such MECO approval shall be by phone, or by e-mail, or in writing to the customer.

REVISED SHEET NO. 62B
Effective

MAUI DIVISION

Rider T (Continued)

c. The customer must notify MECO as far in advance as possible, but not less than 1 hour before performing such emergency maintenance on his equipment or load during the on-peak period. Such notice shall be by phone, e-mail, or in writing. MECO may approve the customer's request on the basis of available capacity. Service to the customer under this condition may be interrupted at any time when MECO's system conditions dictate the necessity to interrupt service, or when in MECO's sole judgment the system may be impaired or the startup of another unit would be uneconomic.

d. The customer's request to operate its load during the on-peak period under this condition cannot exceed four (4) times within a 12-month period.

Superseding Revised Sheet No. 68
Effective April 15, 1999

REVISED SHEET NO. 68
Effective

MAUI DIVISION

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 25 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders "M", "T","I", Schedule "TOU-J" and Schedule "TOU-P". This rate is closed to new customers after _____, 2007.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month	$100.00
DEMAND CHARGE - (To be added to Customer Charge)	
All On-Peak Kw of billing demand - per month	$25.00 per kw
ENERGY CHARGE - (To be added to Customer and Demand Charges)	
All On-Peak Kwhr per month - per Kwhr	25.5003 cents
All Off-Peak Kwhr per month - per Kwhr	21.2153 cents

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge calculation for each month shall be the highest of the maximum on-peak demand for such month, but not less than 25 kW.

Superseding Revised Sheet No. 68A
Effective May 5, 1997

REVISED SHEET NO. 68A
Effective

MAUI DIVISION

Schedule "U" (Continued)

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and peak load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month, but not less than 25 kilowatts.

Power Factor:

For customers with demands in excess of 200 kilowatts, the following power factor adjustment will apply to the energy and demand charges.

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

The average monthly power factor will be determined from the readings of a Kwh meter and kVarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kVarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	4.4%
Distribution voltage supplied without further transformation	1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Superseding Sheet No. 68B
Effective August 18, 1994

REVISED SHEET NO. 68B
Effective

MAUI DIVISION

Schedule "U" (Continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Clause:

The Integrated Resource Planning Adjustment provided in the Integrated Cost Recovery Clause shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Term of Contract:

Not less than one year.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 83
Effective

MAUI DIVISION

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

Service under this Schedule shall be limited to a total of 300 meters.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service - per month	$7.50/month
Three-Phase Service - per month	$12.00/month

ENERGY CHARGES - ¢ per kWh:

Base Charges

First 350 kWh per month - per kWhr	28.3221 ¢/kWhr
Next 850 kWh per month - per kWhr	29.1367 ¢/kWhr
All kWh over 1,200 kWh per month - per kWhr	29.6748 ¢/kWhr

Time-of-Use Charges

Priority Peak Period - per kWhr	5.0 ¢/kWhr
Mid-Peak Period - per kWhr	2.5 ¢/kWhr
Off-Peak Period - per kWhr	- 5.0 ¢/kWhr

SHEET NO. 83A
Effective

MAUI DIVISION

SCHEDULE TOU-R (Continued)

MINIMUM CHARGE:

The minimum charge shall be $17.00.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m., Monday-Friday
Mid-Peak:	7:00 a.m.-5:00 p.m., Monday-Friday 7:00 a.m.-9:00 p.m., Saturday-Sunday
Off-Peak:	9:00 p.m.-7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

SHEET NO. 83B
Effective

MAUI DIVISION

SCHEDULE TOU-R (Continued)

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:
The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:
The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:
Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 84
Effective

MAUI DIVISION

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

Service under this Schedule shall be limited to a total of 100 meters.

RATE:

CUSTOMER CHARGE:	
Single-Phase Service - per month	$25.00/month
Three-Phase Service - per month	$40.00/month

ENERGY CHARGE: (To be added to Customer and Demand Charge)	
Priority Peak Period - per kWhr	34.8037 ¢/kWhr
Mid-Peak Period - per kWhr	32.3037 ¢/kWhr
Off-Peak Period - per kWhr	24.8037 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SHEET NO. 84A
Effective

MAUI DIVISION

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

SHEET NO. 84B
Effective

MAUI DIVISION

SCHEDULE TOU-G - continued

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 85
Effective

MAUI DIVISION

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule U, and Schedule TOU-P.

RATE:

CUSTOMER CHARGE:	
Single-Phase Service - per month	$60.00/month
Three-Phase Service - per month	$75.00/month
DEMAND CHARGE - (To be added to Customer and Energy Charge)	
Priority Peak - per kW of billing demand	$16.00/kW
Mid-Peak - per kW of billing demand	$12.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)	
Priority Peak Period - per kWhr	30.9283 ¢/kWhr
Mid-Peak Period - per kWhr	28.9283 ¢/kWhr
Off-Peak Period - per kWhr	18.9283 ¢/kWhr

SHEET NO. 85A
Effective

MAUI DIVISION

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 85B
Effective

MAUI DIVISION

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 86
Effective

MAUI DIVISION

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule TOU-P.

RATE:

CUSTOMER CHARGE:	$385.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$19.50/kW
Mid-Peak	- per kW of billing demand	$18.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	29.2018 ¢/kWhr
Mid-Peak Period	- per kWhr	27.2018 ¢/kWhr
Off-Peak Period	- per kWhr	17.2018 ¢/kWhr

SHEET NO. 86A
Effective

MAUI DIVISION

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 200 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m.,	Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m.,	Monday - Friday
	7:00 a.m. - 9:00 p.m.,	Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m.,	Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 200 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 86B
Effective

MAUI DIVISION

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 81
Effective April 15, 1999

REVISED SHEET NO. 81
Effective

LANAI DIVISION

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 25 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders "M", "T","I", Schedule "TOU-J, and Schedule "TOU-P". This rate is closed to new customers after _____, 2007.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month	$100.00
DEMAND CHARGE - (To be added to Customer Charge)	
All On-Peak kw of billing demand - per kw	$25.00
ENERGY CHARGE - (To be added to Customer and Demand Charges)	
All On-Peak Kwhr per month - per Kwhr	34.9321 cents
All Off-Peak Kwhr per month - per Kwhr	28.9215 cents

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charges applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge of calculation for each month shall be the highest of the maximum on-peak demand for such month, but not less than 25 kW.

Superseding Revised Sheet No. 81A
Effective May 5, 1997

REVISED SHEET NO. 81A
Effective

LANAI DIVISION

Schedule "U" (Continued)

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and peak load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month, but not less than 25 kilowatts.

Power Factor:

For customers with demands in excess of 200 kilowatts, the following power factor adjustment shall apply to the energy and demand charges.

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

The average monthly power factor will be determined from the readings of a Kwh meter and KVarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The KVarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	4.4%
Distribution voltage supplied without further transformation	1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Superseding Sheet No. 81B
Effective August 18, 1994

REVISED SHEET NO. 81B
Effective

LANAI DIVISION

Schedule "U" (Continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Clause:

The Integrated Resource Planning Adjustment provided in the Integrated Cost Recovery Clause shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Term of Contract:

Not less than five years.

Rules and Regulation:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 87
Effective May 5, 1997

REVISED SHEET NO. 87
Effective

LANAI DIVISION

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers in rate Schedule "J", "K" or "P" but cannot be used in conjunction with the load management Rider M, Schedules "U", "TOU-J" or "TOU-P".

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., Daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., Daily

RATE:

The rate(s) for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate schedule, except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month		$10.00
TIME-OF-DAY ENERGY CHARGE ADJUSTMENTS:		
On-Peak Energy Surcharge	- all on-peak kWhr	+ 2.0 cents/kwh
Off-Peak Energy Credit	- all off-peak kWhr	- 3.0 cents/kwh

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge. In addition, the average energy charge computed from the regular energy charge and the above Time-of-Day energy charge adjustments including the energy cost adjustment, cannot be lower than the off-peak avoided energy cost at the metering point.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak Kw demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

Superseding Revised Sheet No. 87A
Effective August 18, 1994

REVISED SHEET NO. 87A
Effective

LANAI DIVISION

Rider T (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

MEASUREMENT OF TIME-OF-DAY ENERGY AND DEMAND:

The Company shall install a time-differentiating meter to measure the customer's energy consumption and peak kw demand during the time-of-use rating periods.

TERMS OF AGREEMENT:

The customer applying for service under this Rider shall sign a standard Rider T agreement form with the Company. Service under this Rider shall not be less than five years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of discount received under this Rider.

A customer may perform emergency maintenance on his equipment or load served under this rider during the on-peak period and the customer's maximum demand during that time will not be considered in the determination of the billing kw demand under the following conditions:

a. The conditions under which the customer may perform emergency maintenance on his equipment or load during on-peak period will be defined in the customer's contract.

b. The customer may perform such emergency maintenance during on-peak period only when approved by MECO, and will operate only for the duration approved by MECO. Such MECO approval shall be by phone, or by e-mail, or in writing to the customer.

SHEET NO. 87B
Effective

LANAI DIVISION

Rider T (Continued)

c. The customer must notify MECO as far in advance as possible, but not less than 1 hour before performing such emergency maintenance on his equipment or load during the on-peak period. Such notice shall be by phone, by e-mail, or in writing. MECO may approve the customer's request on the basis of available capacity. Service to the customer under this condition may be interrupted at any time when MECO's system conditions dictate the necessity to interrupt service, or when in MECO's sole judgment the system may be impaired or the startup of another unit would be uneconomic.

d. The customer's request to operate its load during the on-peak period under this condition cannot exceed four (4) times within a 12-month period.

SHEET NO. 95
Effective

LANAI DIVISION

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

Service under this Schedule shall be limited to a total of 300 meters.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service - per month	$7.50/month
Three-Phase Service - per month	$12.00/month

ENERGY CHARGES - ¢ per kWh:

Base Charges

First 250 kWh per month - per kWhr	33.2505 ¢/kWhr
Next 500 kWh per month - per kWhr	33.7571 ¢/kWhr
All kWh over 750 kWh per month - per kWhr	34.5426 ¢/kWhr

Time-of-Use Charges

Priority Peak Period - per kWhr	5.0 ¢/kWhr
Mid-Peak Period - per kWhr	2.5 ¢/kWhr
Off-Peak Period - per kWhr	- 5.0 ¢/kWhr

SHEET NO. 95A
Effective

LANAI DIVISION

SCHEDULE TOU-R (Continued)

MINIMUM CHARGE:

The minimum charge shall be $17.00.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m., Monday-Friday
Mid-Peak:	7:00 a.m.-5:00 p.m., Monday-Friday 7:00 a.m.-9:00 p.m., Saturday-Sunday
Off-Peak:	9:00 p.m.-7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

SHEET NO. 95B
Effective

LANAI DIVISION

SCHEDULE TOU-R (Continued)

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 96
Effective

LANAI DIVISION

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

Service under this Schedule shall be limited to a total of 100 meters.

RATE:

CUSTOMER CHARGE:	
Single-Phase Service - per month	$30.00/month
Three-Phase Service - per month	$45.00/month
ENERGY CHARGE: (To be added to Customer and Demand Charge)	
Priority Peak Period - per kWhr	40.4062 ¢/kWhr
Mid-Peak Period - per kWhr	37.9062 ¢/kWhr
Off-Peak Period - per kWhr	30.4062 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SHEET NO. 96A
Effective

LANAI DIVISION

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

SHEET NO. 96B
Effective

LANAI DIVISION

SCHEDULE TOU-G - continued

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 97
Effective

LANAI DIVISION

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule "U", and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE:		
Single-Phase Service	- per month	$55.00/month
Three-Phase Service	- per month	$70.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)		
Priority Peak	- per kW of billing demand	$13.50/kW
Mid-Peak	- per kW of billing demand	$9.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)		
Priority Peak Period	- per kWhr	40.4946 ¢/kWhr
Mid-Peak Period	- per kWhr	38.4946 ¢/kWhr
Off-Peak Period	- per kWhr	28.4946 ¢/kWhr

SHEET NO. 97A
Effective

LANAI DIVISION

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%.

SHEET NO. 97B
Effective

LANAI DIVISION

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 98
Effective

LANAI DIVISION

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE:	$210.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$42.00/kW
Mid-Peak	- per kW of billing demand	$22.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	36.8390 ¢/kWhr
Mid-Peak Period	- per kWhr	34.8390 ¢/kWhr
Off-Peak Period	- per kWhr	24.8390 ¢/kWhr

SHEET NO. 98A
Effective

LANAI DIVISION

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 200 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 200 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 98B
Effective

LANAI DIVISION

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 113
Effective April 15, 1999

REVISED SHEET NO. 113
Effective

MOLOKAI DIVISION

SCHEDULE "N"

Contract Off-Peak And Interruptible Service

Availability:

Applicable to service only between the hours of 10:00 p.m. and 6:00 a.m. daily, supplied and metered at a single voltage and delivery point. Service under this schedule shall be subject to disconnection by the utility under the terms and conditions set fort in the contract agreement, or when required by the system generation capacity. This Schedule shall be closed to new accounts after _____, 2007.

Rate:

CUSTOMER CHARGE - per month	$75.00
DEMAND CHARGE: (To be added to Customer Charge)	
All kw of billing demand	$3.50 per month per kw
ENERGY CHARGE: (To be added to Customer and Demand Charges)	
All kwhr per month - per kwhr	23.0823¢ per kwhr

Minimum Charge:

The minimum monthly charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand, but not less than $350.00 per month. The kilowatts of demand for the minimum demand for such month shall be the highest of the maximum demand for such month, the greatest maximum demand of the preceding eleven months, or 100 kw.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kw during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the maximum demand for such month or the mean of the current monthly maximum demand and the greatest maximum demand for the preceding eleven months, whichever is the higher, but not less than 100 kw.

Superseding Sheet No. 114
Effective August 18, 1994

REVISED SHEET NO. 114
Effective

MOLOKAI DIVISION

SCHEDULE "N" (continued)

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 90%. For each 1% the average power factor is above or below 90%, the demand and energy charges as computed above shall be decreased or increased, respectively, by 0.15%. The power factor shall be computed to the nearest whole percent. In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a Kwh meter and a Kvarh meter. The Kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Primary Supply Voltage Service:

Where, at the option of the Company, service is delivered and metered at the primary supply line voltage, the above demand and energy charges will be decreased by 1.1%. When customers' transformers are adjacent to the delivery point, the Company may permit the customer to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the service is metered on the secondary side of the customers' transformers, the above demand and energy charges will be decreased by 0.5%.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Clause:

The Integrated Resource Planning Adjustment provided in the Integrated Resource Cost Recovery Clause shall be added to the Customer, Demand and Energy Charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 117
Effective April 15, 1999

REVISED SHEET NO. 117
Effective

MOLOKAI DIVISION

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 25 kilowatts per month and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders "M", "T","I", Schedule "TOU-J" and Schedule "TOU-P". This rate is closed to new customers after _____. 2007.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month	$100.00
DEMAND CHARGE - (To be added to Customer Charge)	
All On-Peak Kw of billing demand - per Kw	$25.00
ENERGY CHARGE - (To be added to Customer and Demand Charges)	
All On-Peak Kwhr per month - per Kwhr	34.7806 cents
All Off-Peak Kwhr per month - per Kwhr	23.0823 cents

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge calculation for each month shall be the highest of the maximum on-peak demand for such month, but not less than 25 kW.

Superseding Revised Sheet No. 118
Effective May 5, 1997

REVISED SHEET NO. 118
Effective

MOLOKAI DIVISION

Schedule "U" (Continued)

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and peak load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month, but not less than 25 kilowatts.

Power Factor:

For customers with demands in excess of 100 kilowatts, the following power factor adjustment will apply to the energy and demand charges.

The above energy and demand charges are based upon an average monthly power factor of 90%. For each 1% the average power factor is above or below 90%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%.

The average monthly power factor will be determined from the readings of a Kwh meter and kVarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kVarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	4.4%
Distribution voltage supplied without further transformation	1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Superseding Sheet No. 119
Effective August 18, 1994

REVISED SHEET NO. 119
Effective

MOLOKAI DIVISION

Schedule "U" (Continued)

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Clause:

The Integrated Resource Planning Adjustment provided in the Integrated Cost Recovery Clause shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Term of Contract:

Not less than one year.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 127
Effective May 5, 1997

REVISED SHEET NO. 127
Effective

MOLOKAI DIVISION

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers on rate Schedule "J", "K", or "P" but cannot be used in conjunction with the load management Rider M, Schedules "U", "TOU-J" or "TOU-P".

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., Daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., Daily

RATE:

The rate(s) for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate schedule, except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month		$10.00
TIME-OF-DAY ENERGY CHARGE ADJUSTMENTS:		
On-Peak Energy Surcharge	- all on-peak kwh	+ 2.0 cents/kwh
Off-Peak Energy Credit	- all off-peak kwh	- 3.0 cents/kwh

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge. In addition, the average energy charge computed from the regular energy charge and the above Time-of-Day energy charge adjustments including the energy cost adjustment, cannot be lower than the off-peak avoided energy cost at the metering point.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak Kw demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

Superseding Sheet No. 128
Effective August 18,1994

REVISED SHEET NO. 128
Effective

MOLOKAI DIVISION

Rider T (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

MEASUREMENT OF TIME-OF-DAY ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and peak kW demand during the time-of-day rating periods.

TERMS OF AGREEMENT:

The customer applying for service under this Rider shall sign a standard Rider T agreement form with the Company. Service under this Rider shall not be less than five years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of discount received under this Rider.

A customer may perform emergency maintenance on his equipment or load served under this rider during the on-peak period and the customer's maximum demand during that time will not be considered in the determination of the billing kw demand under the following conditions:

a. The conditions under which the customer may perform emergency maintenance on his equipment or load during on-peak period will be defined in the customer's contract.

b. The customer may perform such emergency maintenance during on-peak period only when approved by MECO, and will operate only for the duration approved by MECO. Such MECO approval shall be by phone, or by e-mail, or in writing to the customer.

SHEET NO. 128A
Effective

MOLOKAI DIVISION

Rider T (Continued)

c. The customer must notify MECO as far in advance as possible, but not less than 1 hour before performing such emergency maintenance on his equipment or load during the on-peak period. Such notice shall be by phone, by e-mail, or in writing. MECO may approve the customer's request on the basis of available capacity. Service to the customer under this condition may be interrupted at any time when MECO's system conditions dictate the necessity to interrupt service, or when in MECO's sole judgment the system may be impaired or the startup of another unit would be uneconomic.

d. The customer's request to operate its load during the on-peak period under this condition cannot exceed four (4) times within a 12-month period.

SHEET NO. 135
Effective

MOLOKAI DIVISION

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

Service under this Schedule shall be limited to a total of 300 meters.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service - per month	$7.50/month
Three-Phase Service - per month	$12.00/month

ENERGY CHARGES - ¢ per kWh:

Base Charges

First 250 kWh per month - per kWhr	34.3732 ¢/kWhr
Next 500 kWh per month - per kWhr	35.5288 ¢/kWhr
All kWh over 750 kWh per month - per kWhr	35.7843 ¢/kWhr

Time-of-Use Charges

Priority Peak Period - per kWhr	5.0 ¢/kWhr
Mid-Peak Period - per kWhr	2.5 ¢/kWhr
Off-Peak Period - per kWhr	- 5.0 ¢/kWhr

SHEET NO. 135A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-R (Continued)

MINIMUM CHARGE:

The minimum charge shall be $17.00.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m., Monday-Friday
Mid-Peak:	7:00 a.m.-5:00 p.m., Monday-Friday 7:00 a.m.-9:00 p.m., Saturday-Sunday
Off-Peak:	9:00 p.m.-7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

SHEET NO. 135B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-R (Continued)

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 136
Effective

MOLOKAI DIVISION

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

Service under this Schedule shall be limited to a total of 100 meters.

RATE:

CUSTOMER CHARGE:	
Single-Phase Service - per month	$23.00/month
Three-Phase Service - per month	$34.00/month

ENERGY CHARGE: (To be added to Customer and Demand Charge)	
Priority Peak Period - per kWhr	46.7728 ¢/kWhr
Mid-Peak Period - per kWhr	44.2728 ¢/kWhr
Off-Peak Period - per kWhr	36.7728 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SHEET NO. 136A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

SHEET NO. 136B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-G - continued

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 137
Effective

MOLOKAI DIVISION

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 100 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule "U", and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE:		
Single-Phase Service	- per month	$42.00/month
Three-Phase Service	- per month	$52.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)		
Priority Peak	- per kW of billing demand	$23.75/kW
Mid-Peak	- per kW of billing demand	$11.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)		
Priority Peak Period	- per kWhr	38.4868 ¢/kWhr
Mid-Peak Period	- per kWhr	36.4868 ¢/kWhr
Off-Peak Period	- per kWhr	26.4868 ¢/kWhr

SHEET NO. 137A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%.

SHEET NO. 137B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 138
Effective

MOLOKAI DIVISION

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 100 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule "TOU-P".

RATE:

CUSTOMER CHARGE:	$85.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$14.75/kW
Mid-Peak	- per kW of billing demand	$11.00/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	36.5525 ¢/kWhr
Mid-Peak Period	- per kWhr	34.5525 ¢/kWhr
Off-Peak Period	- per kWhr	24.5525 ¢/kWhr

SHEET NO. 138A
Effective

MOLOKAI DIVISION

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 100 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 100 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 138B
Effective

MOLOKAI DIVISION

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.4%
Distribution voltage supplied without further transformation	-1.1%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.8% and 0.5%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

LOL-IR-39

Ref: HECO T-7, Page 4, Lines 8 through 13.

"The Hawaiian Electric Companies' proposals for TOU rate options are reasonable because they are based on rate case costs (Hawaiian Electric 2009 test year, HELCO 2006 test year and MECO 2007 test year), and the proposed TOU rate designs have been agreed upon in settlement agreements by all parties to those respective rate cases. These rate options provide to customers an opportunity to shift load as a tool to manage their electric bills." (HECO T-7, 4:8-13)

Would HECO be open to having non-profits, trade groups, and non-HECO utility companies intervene in Time Of Use Rate dockets?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies do not expect to have a docket focused only on time of use rates.

LOL-IR-40

Ref: HECO T-7, Page 9, Lines 13 through 15.

"The Hawaiian Electric Companies have not studied the difference in participation rate and peak demand reduction between TOU rate implementations that are opt-in, opt-out, or mandatory." (HECO T-7, 9: 13-15)

Why?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies expect time-of-use ("TOU") rate implementation to evolve as the Hawaiian Electric Companies move toward placing AMI meters system-wide. In recent years, the Hawaiian Electric Companies plans for TOU rate implementation have been to broaden the availability of opt-in TOU rates to increase customer choice of rates. Prior to the June 20, 2008 implementation of approved TOU rate options in the Hawaiian Electric Company 2005 test year rate case, TOU rate options were available only to medium and large commercial customers. This is still the case at Hawaii Electric Light Company and at Maui Electric Company pending approval of residential and small commercial customer TOU rate options in their current open rate cases (these are TOU rate options that are also proposed for approval in this docket). As part of the Energy Agreement, the Hawaiian Electric Companies have committed to mandatory TOU rates for commercial customers once AMI meter placement is completed.

LOL-IR-41

Ref:

How specifically will AMI lead to Peak Shaving?

Hawaiian Electric Companies' Response:

The AMI network can be utilized to send outbound commands to end-use devices to manage peak demand. This can include direct load control switches, smart thermostats, smart appliances, and to trigger inputs to energy management systems, which can be programmed to respond to control signals sent by the utility.

Hawaii Solar Energy Association & Hawaii Renewable Energy Alliance

HSEA-HREA-IR-14

Ref: HECO T-1, Page 2, Lines 3 through 5.

Referencing page 2, lines 3 to 5 of HECO T-1, HREA and HSEA understands that one key objective of HECO's proposed AMI project is to capture "fundamental improvements in labor intensive processes ..." We understand that there will be "head count" reductions in meter reading and field services. Will there be other workforce reductions?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies have not identified workforce reductions beyond the areas of meter reading and filed services.

HSEA-HREA-IR-15

Ref: HECO T-1, Page 2, Lines 3 through 17.

Referencing page 2, lines 3 to 17 of HECO T-1 and cost-benefit analysis presented in HECO T-3, HREA and HSEA understand that the: (i) non-discounted cost-benefit ratios for the implementation of the AMI Project are estimated to be 1.0 to 1.42, and (ii) HECO Companies anticipate up to 20 years to payback the projected costs of $115M. We observe: (i) given the anticipated 15 to 20 year service lifetime of smart meters and other AMI elements, the AMI Project cost proposal would NOT appear to be conservative, and (ii) in reality, the benefits/costs will require a number of AMI-enabled measures, such as demand response, in order to provide true benefits to the ratepayer. Agree or disagree?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies do not consider the estimated project cost proposal to be conservative. The updated estimated project costs, submitted as Attachment 1 to the Hawaiian Electric Companies' response to CA-IR-35, originate from the AMI Financial model, submitted as Attachment 1 to PUC-IR-23. HECO T-3 (pages 3 through 8) explains the development of the estimated project costs. The AMI's cost-benefit analysis presented in HECO T-3 (pages 18 through 19) only reflects the estimated costs and estimated quantified benefits presented in Attachment 1 to the response to CA-IR-35.

The Hawaiian Electric Companies agree that AMI-enabled measures such as demand response are expected to improve the benefits from the AMI system. However, the incremental benefits can only be achieved with the incurrence of additional costs. Future programs such as demand response will require incremental cost-benefit analyses to be completed, in a similar fashion to the proposed AMI system. Programs that can leverage the AMI network to minimize costs will be the most attractive from a benefit-cost ratio perspective.

HSEA-HREA-IR-16

Ref: HECO T-1, Page 4, Lines 10 through 13.

Referencing page 4, lines 10 to 13 of HECO T-1, how long a period will the installation of smart meters to be on a "first-come, first-served basis?" And how long will there be an "optional" period for implementing TOU rates by request? At what point do the installation of smart meters and implementation of TOU rates become mandatory? Finally, will HECO exempt customers from TOU tariffs if they are not able to modify their usage pattern?

Hawaiian Electric Companies' Response:

In the instant docket, the Hawaiian Electric Companies' requested

> *"immediate approval to begin installing, on a first-come, first-served basis, advanced meters for all customers that request them and to implement TOU rates on an interim basis for customers requesting the installation of advanced meters"*

The installation of AMI meters on a "first-come, first-served basis" will generally occur in advance of full-scale deployment. As indicated in Mr. Young's testimony (HECO T-7, page 8, lines 15-24), customers will be able to request participation in time-of-use ("TOU") rates before and during the period of AMI meter deployment. AMI meters will be installed at all customer locations with the exception of those commercial and industrial customers who have MV90 meters. The Hawaiian Electric Companies have proposed to implement mandatory TOU rates to commercial and industrial customers by customer class as AMI meters placements are completed. In order to do so, the Companies will have to have completed meter placement for all customers in a class and have to have a Commission-approved set of mandatory TOU rates for that class. The Hawaiian Electric Companies have not considered exempting commercial customers from mandatory TOU rates if they are unable to modify their usage patterns. As indicated in Mr. Young's testimony (HECO T-7, page 9, lines 2-8), the Companies are still

considering how TOU rates will apply to non-commercial customers after the AMI meter deployment.

HSEA-HREA-IR-17

Ref: HECO T-1, Page 4, Lines 14 through 19.

Referencing page 4, lines 14 to 19 of HECO T-1, it appears to HREA and HSEA that the HECO Companies have determined that all customers are to be on TOU rates, and perhaps residential customers on both TOU and inclining block rates. Is this correct? Or will the HECO Companies conduct additional pilot projects on both TOU and inclining blocks, and make decisions moving forward based on actual experience of demand and energy savings within individual customer classes? Finally, how will this effort be coordinated with the Public Benefits Fund Administrator?

Hawaiian Electric Companies' Response:

The referenced lines identify the Hawaiian Electric Companies' request for expedited approval of proposed time-of-use ("TOU") rates for residential and commercial/industrial ("C&I") customers that would be implemented on an interim basis for customers requesting the installation of advanced meters. See also the Hawaiian Electric Companies' response to HSEA-HREA-IR-16. Customers who elect to participate in TOU rates will be able to participate in energy efficiency programs that are coordinated by the Public Benefits Fee Administrator.

HSEA-HREA-IR-18

Ref: HECO T-1, Page 5, Lines 3 through 11.

Referencing page 5, lines 3 to 11 of HECO T-1, it appears to HREA and HSEA that the selection of Sensus Metering Systems, Inc. was essentially a "sole source" procurement, as Sensus was the only vendor capable of meeting the HECO Companies' requirements for a two-way wireless (non-mesh, RF) network and a meter data management system. Is this correct? Has that situation changed, i.e., are there more vendors that could meeting the HECO Companies' requirements now?

Hawaiian Electric Companies' Response:

This is partially correct. Sensus is the proposed provider of the AMI meters and the AMI network. Sensus is not the provider of the Meter Data Management System ("MDMS"). Other AMI vendors provide competitive products and services but only Sensus has a licensed (single-user) frequency, fixed tower AMI solution. Other notable AMI vendors are discussed in part b of the Hawaiian Electric Companies' response to HSEA-HREA-IR-8 and HECO T-2 (page 19, lines 1-9.

HSEA-HREA-IR-19

Ref: HECO T-1, Page 6, Lines 5 through 8.

Referencing page 6, lines 5 to 8 of HECO T-1, please explain how AMI will help "support the integration of increased levels of renewables and distributed energy sources into the Companies' grids." Also, please defined "distributed energy sources."

Hawaiian Electric Companies' Response:

The proposed AMI network has the capability to provide time-series voltage, current, and other status information from the utility grid. This includes voltage and usage information all the way down to the customer level. This data will be directly usable in renewable and distributed energy integration studies as well as for operational purposes in the future. The AMI network can also play an important role in providing a communications medium to transmit data from low-cost wind and solar sensors distributed throughout the Hawaiian Electric Companies' service territory. These sensors could be used with appropriate analytical engines to manage variations in power flow from renewable and distributed energy sources.

According to the National Renewable Energy Laboratory:

"Distributed energy refers to a variety of small, modular power-generating technologies that can be combined with load management and energy storage systems to improve the quality and/or reliability of the electricity supply. They are 'distributed' because they are placed at or near the point of energy consumption, unlike traditional 'centralized' systems, where electricity is generated at a remotely located, large-scale power plant and then transmitted down power lines to the consumer.

Implementing distributed energy can be as simple as installing a small, stand-alone electricity generator to provide backup power at an electricity consumer's site. Or it can

be a more complex system, highly integrated with the electricity grid and consisting of electricity and thermal generation, energy storage, and energy management systems. Consumers sometimes own the small-scale, on-site power generators, or they may be owned and operated by the utility or a third party.

Distributed energy encompasses a wide range of technologies including wind turbines, solar power, fuel cells, micro-turbines, reciprocating engines, load reduction technologies, and battery storage systems. The effective use of grid-connected distributed energy resources can also require power electronic interfaces and communications and control devices for efficient dispatch and operation of generating units."

HSEA-HREA-IR-20

Ref: HECO T-1, Page 6, Lines 14 through 16.

Referencing page 6, lines 14 to 16 of HECO T-1, please clarify the "ability of the AMI Network to provide grid-control functions?" Specifically, would grid-control functions include load management measures such as turning loads "off and on" for peak shaving and/or frequency regulation? If so, have the HECO Companies quantified the amount of load reduction and frequency regulation that might be achievable on each island gird? If not, when could this analysis be completed? Please explain.

Hawaiian Electric Companies' Response:

AMI vendors are extending their capabilities beyond metering. Vendors are also working on developing software and hardware platforms to provide load control functionality (i.e., turning water heaters, air conditioners, and water pumps on/off or using devices such as Smart Thermostats which provide a more sophisticated form of control). Load reductions targets for each Hawaiian Electric Company are set forth in the Energy Agreement and the Hawaiian Electric Companies are actively engaged in completing grid studies, as described in the Hawaiian Electric Companies' response to LOL-IR-1.

HSEA-HREA-IR-21

Ref: HECO T-1, Page 7, Lines 4 through 15.

Referencing page 7, lines 4 to 15 of HECO T-1, HREA and HSEA understand the responsibility for electrical energy efficiency savings in support of our state's energy goals will be shared with the Public Benefits Fund ("PBF") Administrator. Please describe how this responsibility is to be shared, and specifically how much of the 4,300 GWh or electricity use reductions can be achieve from the HECO Companies' efforts versus the PBF Administrator.

Hawaiian Electric Companies' Response:

Act 155 (2009 Session) requires that the Public Utilities Commission establish an Energy Efficiency Portfolio Standard to maximize energy efficiency programs and technologies. While the Hawaiian Electric Companies support energy efficiency, the administration of energy efficiency demand side management programs has been transferred to the Hawaii Energy Efficiency Programs (HEEP) Administrator, Science Applications International Corporation (SAIC) as of July 1, 2009. Hawaiian Electric's understanding is that as the administrator of the energy efficiency programs, SAIC will be primarily responsible for achieving the goals of the Energy Efficiency Portfolio Standard. The Hawaiian Electric Companies will play a supporting role by referring its customers to the HEEP through one-on-one contact between the Companies' account managers and the Hawaiian Electric Companies major customers, through the heco.com website, and via advertising and marketing effects, such as TV, radio and newsprint ads, as well as through brochures and other publications that the Hawaiian Electric Companies will make available at its offices and at community events.

The Hawaiian Electric Companies do have a responsibility to achieve the Renewable Portfolio Standard (RPS) to which energy efficiency contributes up until 2015. Therefore, with respect to the RPS, Hawaiian Electric's understanding is that it has primary responsibility up

until 2015 for energy efficiency and will support the efforts of SAIC with respect to achieving that standard.

HSEA-HREA-IR-22

Ref: HECO T-1, Page 8, Line 13 to Page 9, Line 9.

Referencing page 8, lines 13 to line 9 of page 9 of HECO T-1, what is the timeline for "development of the Smart Grid Roadmap?" Given that this activity may take one or two or more years, is it prudent to proceed with the $115M of request activity in advance of the roadmap? Please explain. For example, would it not be more prudent to proceed with pilot programs to test certain key potential aspects of the Smart Grid first, then adjust the implementation according to the recommendations of the Roadmap activity?

Hawaiian Electric Companies' Response:

Please refer to the Hawaiian Electric Companies' responses to CA-IR-16 (page 5), HSEA-HREA-IR-8 (page 3), LOL-IR-1 (page 5), PUC-IR-4 (page 3), and direct testimony in HECO T-2 (page 26) for a discussion of Smart Grid roadmapping and estimated timelines. Additional discussion regarding AMI and its relationship with future Smart Grid activities is provided in the Hawaiian Electric Companies' response to CA-IR-38. Some Smart Grid functionality has been tested by the Hawaiian Electric Companies (i.e., faulted circuit indicators) and certain key potential aspects of the Smart Grid can be tested in parallel with the proposed AMI deployment. If it is necessary to test certain key potential aspects of the Smart Grid first, then the AMI project implementation could be adjusted accordingly.

HSEA-HREA-IR-23

Ref: HECO T-2, Page 7, Lines 4 through 15.

Referencing page 7, lines 4 to 15 of HECO T-2, HREA and HSEA understand that AMI is the foundation for the Smart Grid. However, we are concerned about the prudency of the rapid deployment of AMI per the HECO Companies' proposal. Please clarify the HECO Companies' overall approach, as it appears to us that once the infrastructure is in place it will have a 15 to 20 year lifetime, and we question whether it is wise to agree to a $102M investment now rather than waiting the one or two years it will take to develop the Smart Grid Roadmap, as proposed by the HECO Companies.

Hawaiian Electric Companies' Response:

Please refer to the Hawaiian Electric Companies' response to HSEA-HREA-IR-22.

HSEA-HREA-IR-24

Ref: HECO T-2, Page 15, Lines 3 through 16.

Referencing page 15, lines 3 to 6 of HECO T-2, have the HECO Companies estimated the amount of federal ARRA funding that might be available and for what aspects of the AMI Project? What is the timeline for applying for ARRA funding?

Hawaiian Electric Companies' Response:

Under DE-FOA-0000058 (American Recovery and Reinvestment Act – Smart Grid Investment Grant Program) ("SGIG"), $300,000 to $20,000,000 was available under the SGIG under the smaller projects category and $20,000,000 to $200,000,000 was available under the larger projects category. The first application deadline for this competitive grant program was August 6, 2009. The Hawaiian Electric Companies chose not to submit an application during this initial round of funding for a Smart Grid project that included AMI. Assuming that funding is available in the second and third rounds of SGIG and the Hawaiian Electric Companies are able to develop a Smart Grid concept that meets all the requirements of SGIG, the Hawaiian Electric Companies may submit an application that includes AMI.

HSEA-HREA-IR-25

Ref: HECO T-2, Page 17, Lines 14 through 16.

Referencing page 17, lines 14 to 16 of HECO T-2, HREA and HSEA agree that AMI Technology is evolving at a rapid pace and we understand that standards-making activities are underway. Will the HECO Companies participate in AMI-related standards-making activities, and how will learning from these activities be used to inform the AMI Project in Hawaii?

Hawaiian Electric Companies' Response:

The AMI Director participates in the Utilities Telecom Council's Smart Networks Council ("UTC/SNC"). UTC/SNC is closely involved with the National Institute of Standards ("NIST") and the Electric Power Research Institute's ("EPRI's") Smart Grid standards development efforts, which include AMI-related standards making activities. To date, activities of NIST and EPRI and the interest by the utility industry motivated Sensus to modify its residential meter platform (iConA product) to be ANSI C12.19 compliant (one of the recommended NIST Smart Grid standards) and to address cyber-security standards on a more aggressive pace. There is a movement towards the use of the Internet Protocol for Smart Grid applications, including AMI. Sensus and many other AMI vendors are attempting to portray their products as IP-enabled.

HSEA-HREA-IR-26

Ref: HECO T-5, Page 3, Lines 18 through 23.

Referencing page 3 of 19, lines 18 to 23 of HECO T-5, which of the HECO Companies' initiatives of the October 20, 2008 Energy Agreement will be further facilitated by the cost savings associated with accelerated cost recovery on new AMI meters?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies have not evaluated which specific initiatives would be further facilitated by the proposed accelerated cost recovery of the investment in the new AMI meters. To clarify, the proposed accelerated recovery of the investment in the new AMI meters will not result in a cost savings. The proposed accelerated cost recovery over a seven-year period would provide the Hawaiian Electric Companies an opportunity to recover their investment in the new AMI meters much more quickly than waiting for recovery under a traditional rate case proceeding mechanism. Further, as discussed by Ms. Tayne Sekimura in HECO T-6, an accelerated cost recovery period could reduce investors' perception of risk by limiting the uncertainty in the recovery of the Companies' investment. In turn, this may help maintain the Companies' current cost of capital and mitigate a potential degradation in credit quality. This will allow for improved cashflow and better position the Companies in obtaining financing for future investment, including the various initiatives that the Companies and the State have agreed to undertake in their October 20, 2008 Energy Agreement.

HSEA-HREA-IR-27

Ref: HECO T-7, Page 2, Lines 10 through 22.

Referencing page 2, lines 10 to 22 of HECO T-7, does HECO have evidence regarding the relative savings (or other advantages) associated with the expected load balancing from the proposed TOU-R structure with two rate periods *(i.e.,* a TOU-R structure in which load is shifted in part into near peak loading) vs. the one with three periods (from test cases HELCO 2006, HECO 2007, MECO 2007)? If so, what is the differential? And, what is the primary source of any differential that may exist?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies do not have studies to determine the relative savings (or other advantages) of a two rate periods structure versus a three rate periods structure for the proposed Schedule TOU-R.

HSEA-HREA-IR-28

Ref: HECO T-7, Page 8, Lines 1 through 7.

Referencing page 8, lines 1 to 7 of HECO T-7, can the HECO Companies clarify their comments with respect to TOU as it intersects with Net Energy Metering, Feed-in Tariff and PV Host. Specifically, are the HECO Companies positing: (a) that time of delivery rates will be addressed in these other dockets, or (b) are they positing that they do not expect time of delivery rates to be addressed at all?

Hawaiian Electric Companies' Response:

The time-of-use ("TOU") rate options available at the Hawaiian Electric Company are available to customers who participate in net energy metering. The TOU rate options proposed for HELCO and MECO will be available to customers who participate in net energy metering once approved either in this docket or in those companies' respective open rate cases. The Hawaiian Electric Companies do not anticipate proposing separate time of delivery rates for net energy metering customers. With regard to the Feed-in Tariff (Docket No. 2008-0273) and PV Host (Docket No. 2009-0098) dockets, the price paid for electricity supplied to the utility, including time of delivery rates, if any, will be determined in those respective dockets.

HSEA-HREA-IR-29

Ref: HECO T-7, Page 9, Line 9 through Page 10, Line 2.

Referencing page 9, line 19 to page 10, line 2 of HECO T-7, HREA and HSEA understand HECO Companies concern that allowing commercial customers to opt out of the TOU system leads to weakened price signals and resultant "less efficient" energy consumption. What is the argument for not applying mandatory TOU across all rates classes?

Hawaiian Electric Companies' Response:

The Hawaiian Electric Companies have not extensively examined the impacts of a mandatory time-of-use ("TOU") rate upon various subsets of non-commercial customers (for example low energy users, average energy users, and high energy users). The Companies would not apply mandatory TOU rates to non-commercial customers if it was determined that some subset of these customers would experience undue hardship because of the level of electric bill amounts under mandatory TOU rates.